IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	Docket No. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASE POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY	)	Docket No. E-01345A-16-0123

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FEDERAL EXECUTIVE AGENCIES'
NOTICE OF FILING DIRECT TESTIMONY OF AMANDA M. ALDERSON

Federal Executive Agencies (FEA) hereby provides notice of filing the Direct Testimony of Amanda M. Alderson in the above referenced dockets.

Dated this 3rd day of February, 2017.

ORIGINAL

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Arizona Corporation Commission
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN)	Docket No. E-01345A-16-0036
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BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	**DOCKET NO. E-01345A-16-0036**
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Direct Testimony and Exhibits of

Amanda M. Alderson

On behalf of

Federal Executive Agencies

February 3, 2017

BAI

BRUBAKER & ASSOCIATES, INC.

Project 10268

BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	**DOCKET NO. E-01345A-16-0036**
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Direct Testimony of Amanda M. Alderson

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BEFORE THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	**DOCKET NO. E-01345A-16-0036**
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Direct Testimony of Amanda M. Alderson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Amanda M. Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Senior Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of Federal Executive Agencies ("FEA"). FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Arizona Public Service Company ("APS") or "Company") and purchase electric utility service from APS. The FEA facilities include local post offices, recruitment offices, and numerous other local federal buildings.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A I will address the filed retail cost of service study ("COSS") of APS, the resulting spread of the required revenue increase, and APS's proposals concerning various rate adjustors and riders.

My silence in regard to any issue should not be construed as an endorsement of APS's position.

I. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE 2015 TEST YEAR COSS.

A. My cost of service findings and recommendations are summarized as follows:

1. I find the Company's proposed jurisdictional and New Mexico retail production and transmission allocation methodologies to be consistent with cost-causation principles. They also follow recently approved allocation methods for the Company and other investor owned utilities ("IOU") in Arizona, and neighboring states. I recommend the Arizona Corporation Commission ("Commission") approve the Company's proposed production and transmission allocation methods in this case for both jurisdictional and retail allocation.

2. While I support the jurisdictional and retail production and transmission allocator methodology, I am proposing corrections to some of the allocation factors:

a. I recommend three corrections to the New Mexico retail production allocator, the first of which is to correct two typographical errors in the input values for class non coincident peak in the COSS. The second is to correct for the double-allocation of fuel and purchased power costs to the legacy Rate AG-1 customers. The third correction is to allocate purchased power costs for fixed capacity payments on the same Average and Excess production demand allocator used elsewhere in the COSS by APS.

b. I recommend APS include a customer component in the development of certain distribution cost allocation factors in its COSS.

   i. The National Association of Regulatory Utility Commissioners ("NARUC") Manual supports the allocation of certain distribution costs using both a customer and demand classification.

   ii. Further, Tucson Electric Power reflects this allocation method in its ongoing base rate case to appropriately reflect the cost to provide distribution services to all types of customers, including solar generating customers. I recommend the Commission accept this change to the COSS.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S PROPOSED REVENUE SPREAD.

A I find the Company's general approach to revenue spread to be reasonable, using the COSS results as a guide, and considering gradualism when apportioning rate increases. Based on my corrected COSS presented in this testimony, I have developed an alternate spread of the revenue increase. My proposed spread will be detailed later in this testimony. It brings most classes closer to a 1.00 indexed rate of return, ensuring the majority of classes are paying nearly their full allocated cost of service, and minimizes the subsidy paid across classes.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S PROPOSED CHANGES TO VARIOUS RATE ADJUSTORS AND RIDERS.

A My findings and recommendations are summarized as follows:

1. I oppose the Company's proposal to include the costs of electric storage contracts in the Power Supply Adjustment mechanism because there are currently no such contracts, and power storage costs are better allocated on a demand basis as opposed to an energy basis.

2. I oppose the Company's proposal to increase the cost cap of the Environmental Improvement Surcharge, but find the cost under-recovery carry over and balancing account proposals to be reasonable. Because the Company's expenses recoverable under this surcharge will reset to zero in this proceeding, it is unnecessary to increase the cost cap.

3. I find the Company's proposal to roll into base rates $10 million in Demand Side Management Adjustment charges to be reasonable. The purpose of this adjustor is to recover costs for approved Demand Side Management projects incurred after a utility's last base rate case up to the test year in its next base rate case.

4. I oppose the Company's proposal to roll into base rates $37.6 million in Renewable Energy Adjustment charges. The Arizona Renewable Energy Standard mandate includes ratepayer cost protections that are muted when costs are removed from the Company's Renewable Energy Adjustment rider and moved into base rates. The Company's proposal also muddies the rate signal to customers working to meet their own internal carbon reduction goals when the additional cost for utility renewable generation is not separated from base rate charges.

5. I oppose the Company's proposed elimination of Rate Rider Schedule AG-1, because the Company's estimate of lost revenues from this program is flawed, the Company has not recorded all reasonable additional revenues gained from this program, and the Company has not fulfilled its Commission-directed obligation to fully explain why it was unable to eliminate all of the lost fixed generation costs from the Rate AG-1 program. I recommend that the Commission correct its cost impact estimates and, based on those results, continue and expand the Rate AG-1 program.

6. I recommend a change to the Company's proposed Rate Rider EPR-6s, designed to provide the Commission-directed export energy payment to rooftop solar customers. The Company's Rider EPR-6s institutes a 100 kW-ac maximum for eligibility to receive the export energy payment recently approved by the Commission in its Value and Cost of Distribution Generation Proceeding. This cap should be removed.

II. APS'S PROPOSED COST OF SERVICE STUDY

Q HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE FILING IN THIS PROCEEDING?

A Yes. I have reviewed the testimony of APS witness Mr. Leland Snook and the COSS he has presented therein. The Company proposes to continue using the production and transmission jurisdictional and retail cost allocators as it used in the last several base rate cases.[1]

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED JURISDICTIONAL PRODUCTION COST ALLOCATION METHOD.

A APS proposes to allocate its fixed (non-variable) production plant costs between jurisdictions using the four coincident peak ("4 CP") method. APS's proposal generally follows cost of service principles, and is unchanged from the last several APS base rate cases. The Company states that it is required by the Federal Energy Regulatory Commission ("FERC") to use the 4 CP methodology.[2]

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED JURISDICTIONAL AND RETAIL TRANSMISSION COST ALLOCATION METHOD.

A APS proposes to allocate its transmission expense directly to the jurisdictional and retail service classes in proportion to the FERC-regulated transmission rates under the APS Open Access Transmission Tariff ("OATT"). The Company first allocates all transmission plant to the wholesale, non-retail jurisdiction, then allocates to the retail classes the transmission expense level based on the applicable OATT transmission

[1]APS responses to FEA 3.3 and 3.4.
[2]Snook Direct Testimony, page 22, lines 13-19.

and ancillary service rates in effect. Offsetting revenues are applied to the wholesale jurisdiction.

APS's OATT rates are regulated by FERC. This retail allocation method aligns with cost-causation principles upheld by FERC by apportioning costs to the retail classes using the OATT rate 12 CP demand methodology.

II.A. Retail Production Cost Allocation

Q PLEASE DESCRIBE THE RETAIL PRODUCTION COST ALLOCATION THAT APS IS PROPOSING IN THIS PROCEEDING.

A Within the Arizona retail jurisdiction, APS proposes continuation of the A&E 1 NCP method for allocating fixed production costs. This method incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy) in developing the production allocation factor. As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year.[3] This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.

Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak demand is then allocated to customer

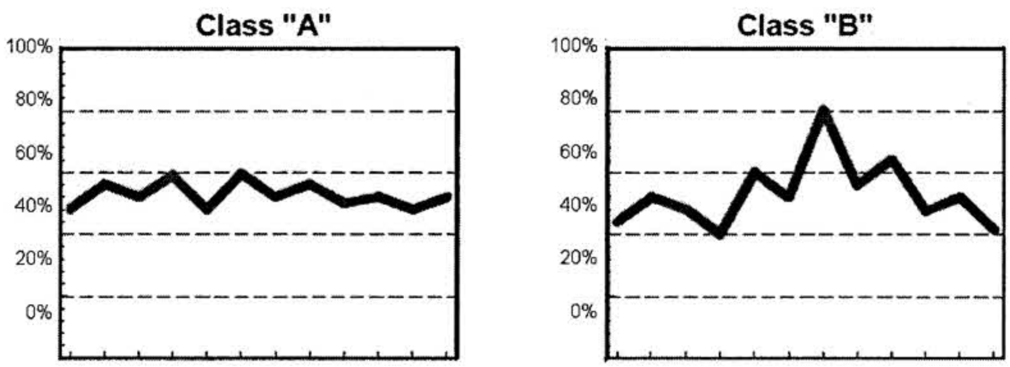
[3]APS uses a slightly different calculation to find class total energy, multiplying the class NCP by the class load factor. This method produces nearly identical results.

classes on the basis of a measure that represents their "peaking" or variability in usage.[4]

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

A As an example, Figure 1 shows two classes that have different monthly usage patterns.

Figure 1
<u>Load Patterns</u>



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[5] than Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment, resulting in higher maintenance cost.

[4] <u>NARUC Electric Utility Cost Allocation Manual</u>, 1992, page 81.
[5] During any specified time period (e.g., month, year), the maximum demand of a class, regardless of when it occurs, is called the non-coincident peak demand.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).

Q DOES THE COMPANY'S PROPOSED A&E ALLOCATION METHOD ALIGN WITH COST CAUSATION?

A Yes. Production plant must be sized to meet the maximum demands imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. The Company's proposed A&E 1 NCP allocation methodology meets this criterion, and has been used by APS in past cases, as approved by the Commission.

Q WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S PROPOSED PRODUCTION COST ALLOCATION?

A I recommend the Commission approve the Company's proposed continued use of this retail production capacity cost allocation methodology. However, I am proposing three changes or corrections to the Company's production allocation.

Q WHAT CHANGES/CORRECTIONS TO THE PRODUCTION COST CLASS ALLOCATOR DO YOU RECOMMEND?

A First, there has been a typographical error in inputting the retail class NCP in the test year for two of the rate classes. I reviewed the primary data source for the class NCP levels, the Company's hourly system load by class,[6] and found that all classes' NCP

[6]APS responses to FEA 2.11, 5.2, and 7.1.

values listed in the COSS allocator development workpaper were correct as calculated in the primary source document, except for two classes. The two classes that did not have correct NCP values were E-32 and E-34. I have corrected those errors.

Q WHAT IS THE SECOND CORRECTION YOU PROPOSE TO THE COMPANY'S PRODUCTION COST ALLOCATION METHOD?

A I recommend that the COSS be corrected to not double-count allocated fuel and purchased power costs to the legacy Rate Rider AG-1 customers. As I will address later in this testimony, the Company is proposing to terminate the Rate Rider AG-1 buy-through program, where large customers had the opportunity to purchase generation supply (i.e., fuel and purchased power costs) from a third-party supplier, and not from APS. To address the Company's proposed termination, its COSS model directly allocates the generation supply costs that Rate Rider AG-1 customers paid to third parties to the individual retail rate classes that included such Rate Rider AG-1 customers. Yet the Company's COSS also allocated test year fuel and purchased power expenses using a retail class energy allocator inclusive of the Rate Rider AG-1 customer loads. This has the effect of double-counting fuel and purchased power costs for the Rate Rider AG-1 customers. I have corrected this error in my COSS by using the Energy2 allocation factor developed by the Company to allocate to all rate classes the generation supply costs that Rate Rider AG-1 customers paid to third parties. This ensures that all customers are paying an equal share of the full pro forma test year fuel and purchased power expenses, inclusive of the additional fuel expenses that would have been necessary to serve the Rate Rider

AG-1 customers, which is estimated by proxy using the fuel costs paid to the third-party suppliers.

Q WHAT IS THE THIRD CHANGE YOU PROPOSE TO THE COMPANY'S PRODUCTION COST ALLOCATOR CALCULATIONS?

A I recommend an adjustment to the allocation of the Company's base fuel costs, to remove a significant amount of fixed capacity payments that APS has improperly included in the total fuel and purchased power "energy" amount in the Test Year.

The APS COSS historical year and pro forma amounts for total fuel and purchased power includes the full amount of costs recovered through the Power Supply Adjustment ("PSA") through the test year period. Mr. Ewen's workpaper WME_04DR indicates that approximately $130.3 million of the net fuel and purchased power total cost of $853.5 million is for Purchased Power. Footnote 6 on this same workpaper states that the Purchased Power total includes costs for both the fixed capacity payments and Purchased Power Agreement ("PPA") energy charges. APS's response to FEA 5.7 further clarifies that $81.8 million of the $130.3 million expense is from fixed capacity payments and $48.5 million is for PPA energy.

Fixed capacity costs totaling approximately 10% of the Company's total test year fuel and purchased power expense should be allocated across rate classes using a production demand allocation factor. I recommend that these PPA capacity costs be allocated across retail customer classes using the same production demand allocator used for other fixed production generation rate base and related expense, the Average and Excess 1 NCP ("A&E") factor.

Q HAVE YOU ADJUSTED THE COMPANY'S COSS TO REFLECT YOUR PROPOSED CHANGE?

A Yes, my Exhibit AMA-1 shows the results of these proposed corrections and changes in the allocation of production costs. The Exhibit AMA-1 format matches that of the Company's COSS results Attachment LRS-04DR, for ease of comparison.

II.B. Distribution Cost Allocation

Q HOW THE DOES THE COMPANY PROPOSE TO ALLOCATE DISTRIBUTION COSTS IN THE COSS?

A Mr. Snook describes at page 23 of his Direct Testimony that APS proposes classifying 100% of distribution-related equipment, aside from meters, as demand-related, and using only distribution demand allocators to allocate these costs across rate classes.

Q WHAT IS YOUR CONCERN WITH THE COMPANY'S 100% DEMAND-RELATED DISTRIBUTION COST ALLOCATION METHOD?

A The FERC Accounts 364-368 include the costs of poles and towers, underground and overhead lines, and transformers. Allocating these costs on only a pure demand basis is not reasonable for at least two reasons: (1) is not supported by the NARUC Manual; and (2) does not reflect the fact that there is a customer-related component to the cost causation of the distribution system. This customer component is associated with the need to "cover the system," and the fact that the Company incurs distribution costs simply to connect customers to the system regardless of their demands.

Q **WHY DO YOU SAY THE NARUC MANUAL DOES NOT SUPPORT THESE DISTRIBUTION-RELATED COSTS BEING CLASSIFIED AS 100% DEMAND-RELATED?**

A Table 6-1 in the NARUC Manual on page 87, replicated below as Table 1, shows clearly that distribution assets in FERC Accounts 360, 361, and 364 through 368 are properly allocated on both a customer- and demand-related allocator.

TABLE 1

Table 6-1 of NARUC Manual – January 1992 Edition
Classification of Distribution Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems	-	-

Footnote 2 to the NARUC Manual table explains:

> The amounts between [demand and customer] classification may vary considerably. A study of the minimum intercept method or other

> appropriate methods should be made to determine the relationships between the demand and customer components.

In other words, the NARUC Manual leaves open the opportunity for a utility company to determine nearly none (zero) of these costs should be classified as customer-related, but only after completing the appropriate study of its distribution system.

Q IS THE COMPANY'S PROPOSAL REASONABLE, TO ASSUME 100% OF THESE DISTRIBUTION ASSET COSTS ARE DEMAND RELATED, ABSENT A STUDY OF ITS DISTRIBUTION SYSTEM?

A No. The distribution system is sized not only to accommodate demand requirements but also to simply connect each customer to the system. This minimum customer connection cost is irrespective of size. The connection equipment necessary is above and beyond the service drop to a customer's premises because there must be an infrastructure to which the service drop can be connected.

Consequently, while a customer's demand requirements will influence the particular size of the distribution facilities installed, the fact that some facilities of at least a minimum size must be constructed relates to the existence and location of customers within the service territory, the distance of conductor, and the number of transformers. Unless these factors are taken into consideration, the COSS will depart from cost-causation.

The central idea behind the minimum system concept is that there is a cost incurred by any utility when it extends its primary or secondary distribution system, replaces a component on those systems, or connects an additional customer to them. By definition, the minimum system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary conductors and cables, poles, substations, etc. The cost of the minimum system, however, is only that portion of the total distribution cost the utility must incur to render service to customers. It does not include costs specifically incurred to meet the peak demand of the customers. Therefore, the minimum system cost is rightfully classified as customer-related, and should be allocated on a customer basis, separate and apart from the distribution costs classified as demand-related.

Q **IF IT IS UNREASONABLE TO CONSIDER THESE DISTRIBUTION ASSET COSTS AS 100% DEMAND RELATED, WHAT PERCENTAGE OF THE ALLOCATION SHOULD BE DEMAND RELATED?**

A In order to determine the best estimate of the percentage of total distribution asset costs that are demand related, a utility company would complete a study of its installed distribution assets, typically termed a Minimum Distribution Study.

A Minimum Distribution Study consists of a review of the distribution assets installed on the Company system that would meet the minimum required to serve a customer. For example, the smallest size pole and smallest size cable, conductor, etc. is determined, and the total book cost for that minimum system is established. This total minimum system cost for each distribution asset, separated by FERC Account number, is then allocated on a customer basis. The remainder of distribution asset costs in those FERC Accounts is allocated on a demand basis.

Alternately, the utility company could follow the Zero-Intercept Method, which is similar to the Minimum Distribution Method, but seeks instead to identify the portion of distribution plant costs related to a hypothetical no-load situation. The Zero-Intercept method often requires considerably more data, and the resulting customer/demand split is usually very similar to the results of the Minimum Distribution Study.

In this proceeding, in the absence of an analytical study to determine proper cost classification for APS, I recommend relying on the results of the Minimum Distribution Study analysis prepared by Tucson Electric Power Company ("TEP") in its current base rate case, Docket No. E-01933A-15-0322.

Q DID TEP PROPOSE USE OF A MINIMUM DISTRIBUTION STUDY IN ITS CURRENT BASE RATE CASE?

A Yes. TEP allocated and classified distribution costs using both a customer-related and demand-related allocator. The Direct Testimony of Company witness Craig Jones filed in Docket No. E-01933A-15-0322 describes the Company's proposed classification and allocation of distribution costs as follows:

> The system distribution plant consists of different facilities that have different cost causation factors. The reason for this is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is the direct result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest transformers cost much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity.[footnote omitted] For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. . . . For facilities located close to the customer, such as transformers, secondary conductor, and secondary poles and even single phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate. (pages 19-20)

* * *

> For distribution plant costs found in FERC Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers. . . . If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory basic service charge, the result is not just and reasonable and causes undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system. . . . For distribution facilities in the accounts related to the power lines and transformers (Account Nos. 364-368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. (Pages 21, 22 and 24).

Q HAS TEP RELIED UPON A MINIMUM SYSTEM APPROACH TO CLASSIFY DISTRIBUTION COSTS BETWEEN CUSTOMER AND DEMAND?

A Yes. Mr. Craig Jones' testimony in the current base rate case cited above explains TEP's use of the minimum system approach.

Q WHAT ARE THE RESULTING CUSTOMER AND DEMAND SPLITS FOR DISTRIBUTION COSTS THAT TEP PROPOSES?

A Schedule G-7 of TEP's minimum filing requirements shows on page 3 the percent split between customer and demand for all FERC distribution accounts. Replicated below in Table 2 are the demand and customer splits for FERC Accounts 364-368 as proposed by APS in the instant proceeding and the splits proposed by TEP in its current base rate case, based on the results of TEP's Minimum Distribution Study analysis.

TABLE 2

Customer / Demand Split

FERC Account	APS Proposed - Instant Proceeding	FEA Proposed - TEP Current Proceeding
364 Poles, Towers, and Fixtures		
Primary		
Demand	75%	36%
Customer	0%	64%
Secondary		
Demand	25%	36%
Customer	0%	64%
365 OH Conductors and Devices		
Primary		
Demand	75%	80%
Customer	0%	20%
Secondary		
Demand	25%	80%
Customer	0%	20%
366 UG Conduit		
Primary		
Demand	100%	0%
Customer	0%	100%
367 UG Conductors and Devices		
Primary		
Demand	84%	59%
Customer	0%	41%
Secondary		
Demand	16%	59%
Customer	0%	41%
368 Line Transformers		
OH Line Transformers		
Demand	20%	76%
Customer	0%	24%
UG Line Transformers		
Demand	80%	76%
Customer	0%	24%

Sources:
APS Docket No. E-01345A-16-0036, COSS and
TEP Docket No. E-01933A-15-0322, Schedule G-7, Sheet 3 of 9.

Q **DO YOU PROPOSE THAT THE TEP CUSTOMER AND DEMAND SPLIT FOR THESE FERC ACCOUNTS BE USED IN APS'S COSS?**

A Yes. Absent a utility-specific analytical study to determine the proper cost classification between demand and customers for APS, I propose that the neighboring utility TEP classification values be used in this base rate case to more accurately classify distribution costs between functions, allocate those costs between customer classes, and therefore finally to determine the most reasonable spread of the overall revenue increase to all customer classes.

Q **HOW HAVE YOU APPLIED TEP'S CUSTOMER DEMAND SPLITS FOR DISTRIBUTION ACCOUNTS IN THE APS COSS?**

A Exhibit AMA-2 shows the derivation of new FERC account allocation factors across customer classes using the demand-related allocation factors proposed by APS and the class customer-related allocation factors for the APS system, but combining the allocation for both demand and customer related factors for each FERC account based on the customer demand splits used by APS in its current base rate case. I then reran the Company's COSS with my adjusted proposed allocation factors for the various FERC distribution accounts and Exhibit AMA-3 provides the results of that COSS, showing only the effect of adjusting the distribution cost allocation. Exhibit AMA-3 does not include my corrections to the COSS production cost allocation calculations.

Q WHAT IS YOUR OVERALL RECOMMENDATION CONCERNING THE COSS FILED BY APS?

A I propose three corrections to the Company's production cost allocation calculations, to allocate purchased power fixed capacity costs in line with other fixed production costs (using the A&E 1 NCP method), to correct the class NCP for two retail classes where inadvertent typos have occurred in entering data into the Company COSS, and to correct for double-counting of Rate Rider AG-1 fuel expenses. I also propose one change to APS's proposed distribution cost allocation, that is, to incorporate a customer-related component in the allocation method for distribution costs found in FERC Accounts 364-368. I have made this change to APS's filed COSS using the customer demand splits proposed by TEP in its current base rate case. My Exhibit AMA-4 shows the combined effect of all four of my proposed adjustments. I recommend that the results of this corrected COSS be used to determine the most reasonable spread of the overall revenue increase approved by the Commission across the various retail customer classes.

III. SPREAD OF THE REVENUE INCREASE

Q HOW DID THE COMPANY DEVELOP ITS PROPOSED SPREAD OF THE REQUIRED REVENUE INCREASE ACROSS THE RETAIL CUSTOMER CLASSES?

A APS Witness Mr. Miessner describes at pages 11-14 of his Direct Testimony that the Company used its COSS results as a guide, but considered the concept of gradualism when determining its final proposed base rate increase for each retail class. Mr. Miessner explains, "In general, rate classes which were most deficient in recovering their cost of service, or which had the lowest percent of cost to serve, received a relatively higher increase. Conversely, rate classes that were least deficient in cost recovery and had higher percent recoveries of cost to serve received a relatively lower allocated increase. . . . The requested increase [for the residential class] is above the proposed system-average increase, but will still leave residential customers below the cost of service. The goal is to gradually bring residential customers more in line with the cost of service over time."[7]

Q DO YOU OPPOSE THE METHODS USED BY APS TO DEVELOP ITS PROPOSED REVENUE SPREAD?

A No, I believe the general concepts used by the Company are reasonable, and used frequently in other jurisdictions in the industry. I do, however, propose that the final revenue increase be based on my corrected proposed COSS results. I have developed Exhibit AMA-5 to show a comparison of the Company's COSS results and proposed revenue increase by rate class, as well as my proposed COSS results and proposed revenue increase.

Exhibit AMA-5 shows that under both my and the Company's COSS model, the Residential Solar Energy class is at a significantly negative rate of return at present rates, meaning that these customers are being significantly subsidized by other classes. The Company proposes to increase base rates to this class at 1.33 times the system average increase, but because of the considerable under-collection of revenues, I recommend the class receive a 2.0 times the system average increase. For all other rate classes providing a rate of return at present rates of less than 0.50, I recommend a 1.5 times the system average increase.[8] This includes

[7]Miessner Direct Testimony, page 12, lines 10-13 and page 14, lines 3-5

[8]The one exception is the Church E-20 class, which is also providing a negative rate of return at present rates, and I have left unchanged the Company's proposed 1.57 times system average increase.

each of the remaining Residential sub-classes. By contrast, the Company's proposed increases for the Residential classes fall no lower than 1.33 times the system average increase and no higher than 1.60 times the system average increase. These indexed increases to the system average can be found in Columns 6 and 10 on Exhibit AMA-5.

After increasing the revenue spread to the classes described above, I then spread back to all other rate classes the revenue differential created through increasing the smaller class revenue apportionment. I allocated this revenue differential based on present base rate revenues, but ensuring no class receives a rate decrease. This method leaves unchanged the relative increases between these classes as originally proposed by the Company.

Q HOW IS YOUR PROPOSED REVENUE INCREASE SPREAD MORE REASONABLE THAN THE COMPANY'S PROPOSED RESULTS?

A Columns 3, 7 and 11 of Exhibit AMA-5 calculate the rate of return ("ROR") at present rates, the Company's proposed rates, and my proposed rates, respectively. Comparing these values for each class shows that my proposal will move each class closer to a 1.00 parity ROR, where 1.00 parity means that the rate class provides an ROR equal to the system average ROR. These proposed ROR metrics are based on my corrected COSS, and they show that my proposed rates make a more meaningful move toward full cost of service, especially for those customer classes providing a negative return, or less than a 0.50 ROR at present rates.

Table 3 below shows a comparison of the Company's and my proposed spread of the revenue increase.

TABLE 3

Comparison of Company and FEA Proposed Revenue Increase
Dollars in Thousands

Rate Class	Present Base Revenues	Company Proposed Increase[1]			FEA Proposed Increase[2]		
		($000)	Percent	Index	($000)	Percent	Index
Residential	$1,486,578	$118,289	8.0%	1.4	$128,694	8.7%	1.5
General Service	1,343,926	44,242	3.3%	0.6	34,513	2.6%	0.4
Water Pumping	28,739	1,649	5.7%	1.0	1,317	4.6%	0.8
Street Lighting	21,082	1,149	5.5%	0.9	906	4.3%	0.7
Dusk to Dawn	8,578	554	6.5%	1.1	455	5.3%	0.9
Total Retail	$2,888,904	$165,884	5.7%	1.0	$165,884	5.7%	1.0

Sources:
1. Schedule H-1
2. Exhibit AMA-5

*Note: Proposed Increase is net after adjustor transfer revenue

IV. MODIFICATIONS TO RATE RIDERS

IV.A. Power Supply Adjustor

Q WHAT IS THE COMPANY'S PROPOSED RECOVERY METHOD FOR THE COST OF ELECTRIC STORAGE CONTRACTS WITH THIRD-PARTY SUPPLIERS?

A Company witness Peter M. Ewen describes at page 29 of his Direct Testimony the Company's proposal to add contract costs with third-party suppliers for electric storage (e.g., batteries) into the Power Supply Adjustment ("PSA") recovery mechanism. The Company does not currently have any such contracts or costs associated, but requests approval to begin including these costs in the PSA if the Company enters into electric storage agreements presumably prior to the filing of the next base rate case.

Q DO YOU FIND THIS COMPANY REQUEST TO BE REASONABLE?

A No, for two reasons. First, electric storage contracts are new and novel and should not be automatically included in the PSA "if and when such transactions occur,"[9] but rather should be fully explored and vetted within the context of a base rate case when the costs are known, and the use of the resource can be assessed.

If the Company's electric storage contract costs are substantial, then there is more reason to allow Staff and all interested parties the opportunity to review the prudence, and used and usefulness, of the contracts in a full base rate case, as opposed to in an expedited annual PSA filing. If the Company's electric storage contract costs are minimal, the Company can more easily postpone recovery of those costs until the next base rate case.

At this point, the Company does not have intentions to contract with any third-party suppliers for electric storage but rather, as Mr. Ewen writes, "The Company may find an opportunity . . . in the near future." The Commission does not need to establish cost recovery for these future, unknown electric storage costs.

Q WHAT IS THE SECOND REASON YOU OPPOSE THE COMPANY'S PROPOSAL?

A Including the costs of contracts with third-party suppliers for electric storage in the PSA would allocate those costs to customers on an energy basis, based on the cost allocation and recovery process within the PSA currently. The Company would record these costs in FERC Account 550,[10] which is allocated in base rates on a demand basis.[11] FERC Account 550 contains purchased power costs, some of which are generally allocated on energy (variable power expenses) and some of which are generally allocated on a demand basis (fixed payments for capacity).

[9]Ewen Direct Testimony, page 29, line 10.
[10]*Id.*, lines 7-8.
[11]APS response to FEA 2.15.

Fixed payments for electric storage could be allocated more reasonably on a demand-related production allocation method since electric storage would operate as an additional peaking capacity resource, not a fuel expense. This is an example of the full review and discernment of electric storage costs that would occur in the context of a full base rate case when such costs have been incurred. For these two reasons I recommend the Commission abstain from approving the Company's proposal to recover future third-party electric storage contract costs through the PSA mechanism.

IV.B. Environmental Improvement Surcharge

Q IS THE COMPANY PROPOSING ANY ADJUSTMENT TO THE ENVIRONMENTAL IMPROVEMENT SURCHARGE ("EIS")?

A Yes. Company witness Mr. Snook explains beginning at page 37 of his Direct Testimony the Company's proposal to first, change the cap on allowable Company cost recovery from $0.00016/kWh (approximately $5 million annually)[12] to $10 million; second, to carry over to each subsequent year any EIS revenue over the annual cap; and third, to include a balancing account to allow the Company to recover its actual EIS-related investments. I disagree with the increase to the cap amount by $5 million but find the second two EIS adjustments that the Company is proposing a reasonable compromise.

Q WHAT COSTS DOES THE EIS RECOVER?

A The EIS allows APS to recover the capital carrying cost of qualified environmental improvement investments that are placed into plant-in-service between APS base

[12]APS response to FEA Data Request 5.11.

rate cases.[13] The Company's EIS Plan of Administration describes these qualified investments as environmental improvement projects necessary for compliance with current or prospective environmental standards required by federal, state, tribal or local laws or regulations, as well as generation plant capacity acquisitions or additions. The individual improvement projects have been accumulating in the EIS since November 2012,[14] and because all of the projects have been placed into plant-in-service through the test year period in this case, the EIS cost recovery amount will be reset to zero in this proceeding. Indeed, Arizona Corporation Commission Staff described the intended operation of the EIS in just this manner in the last base rate case, stating:

> the EIS [is] in the public interest because now APS will invest its own funds to pay for government-mandated environmental controls, and the EIS will only collect the capital carrying costs, subject to a cap equal to the charge currently in place for the EIS. The EIS will be reset to zero on the effective date of new rates adopted in this Decision.[15]

Q SHOULD THE COMPANY'S REQUEST TO DOUBLE THE EIS ANNUAL RATE CAP FROM APPROXIMATELY $5 MILLION TO $10 MILLION BE APPROVED?

A No. The Company has not historically exceeded the annual $5 million cost cap, except in its most recent filing covering the period November 2012 through December 2015, where it exceeded the cap by $985,000.[16] The EIS is intended only to recover capital carrying costs on mandated environmental improvement investments until such time as the full project costs can be included in base rates.[17] Therefore, the

[13]Snook Direct Testimony, page 37, lines 13-26.
[14]APS response to Staff 5.56.
[15]Decision No. 73183, pages 25-26.
[16]APS Response to Staff 5.56, attachment "Staff 5.56_EIS_2016 Filing Workbook_APSRC01193.xlsx"
[17]Snook Direct Testimony, page 37, lines 13-26.

carrying cost of qualifying projects not included in base rates after the conclusion of the instant proceeding will be zero.

It has taken three full years for the EIS carrying cost total to exceed the current $5 million cap. If the Company's mandated environmental projects continue in the near future at a faster pace, which is increasingly uncertain given the changes to the federal government administration post-election, it is more prudent for APS to come in for a full base rate increase in order to move the large amount of new plant-in-service into base rates. A full base rate case would provide the Commission and stakeholders sufficient opportunity to review changes to APS's full cost of service all at the same time.

Further, if the time period between the resetting of the EIS during base rate cases increases, there is an increased likelihood that the carrying cost of capital being earned by the Company on these projects has moved out of sync with the true cost of capital in the then-current market. The Company would have an increased opportunity to avoid a base rate case potentially resetting at a lower level the carrying cost of capital if the allowable cost cap recovery through the EIS is doubled from $5 million to $10 million.

Q SHOULD THE COMPANY'S REQUEST FOR A BALANCING ACCOUNT AND A CARRY-OVER OF THE PRIOR YEAR UNDER-COLLECTION INTO THE SUBSEQUENT YEAR BE APPROVED?

A I find the Company's proposals here to be a reasonable compromise, especially in the event the Company does in fact exceed the current $5 million annual cap at a faster pace than has occurred over the last three years. Allowing APS to carry forward any unrecovered carrying costs, and to true-up its actual EIS revenue collected with the approved EIS rider charge for a given calendar year[18] allows the Company to recover its approved costs while balancing the interests of the ratepayers who should not be required to pay carrying charges at a recovery rate higher than what is typical in the industry during then-current market conditions. I believe allowing the Company the carry-forward and true-up EIS mechanism adjustments will balance the desire on one hand to reduce the expense required to conduct a full utility base rate case with the desire to appropriately review for prudency the environmental improvement projects that the Company has placed into service, as well as to benchmark the capital costs paid by the ratepayers on a growing utility rate base amount.

IV.C. REAC and DSMAC

Q IS THE COMPANY PROPOSING ADJUSTMENTS TO THE RENEWABLE ENERGY ADJUSTMENT CHARGE ("REAC") AND THE DEMAND-SIDE MANAGEMENT ADJUSTMENT CHARGE (DSMAC")?

A Yes. Similar to the EIS mechanism, the Company is proposing to roll into base rates approximately $50 million of revenue currently recovered through the REAC and DSMAC mechanisms. A review of the Company's DSMAC Plan of Administration, and APS's response to FEA 5.12 indicates that there is no discrete cost cap or limit protection for ratepayers under the DSMAC. Instead, the Company is expected to justify its DSMAC expenditures in its annual Plan filings using benefit-to-cost

[18]I understand the Company's proposal concerning the true-up to account only for the differences between prior year and current year retail sales, not instead to allow the Company to charge the full $5 million annual EIS rider capped amount in every calendar year even if the Company's qualified carrying costs did not reach the $5 million level in a given year. The Company's testimony concerning the true-up, Mr. Snook's Direct Testimony at pages 37-41, could be interpreted differently by the Commission. I do not support the Company collecting EIS rider costs above its actual incurred carrying cost amount.

analyses. But the Company is expected to fully recover its prudent costs from ratepayers.

By contrast, the Arizona Renewable Energy Standard and Tariff ("REST") rules codified in Arizona state law establish a class-by-class ratepayer maximum annual cost that can be imposed on Arizona utility customers to subsidize renewable energy development.[19] These customers cap amounts have been increased by Commission order since the REST rules were first put in effect in 2007, as the REST required renewable energy amounts have increased. I find it unreasonable to roll \$37.6 million in REAC costs into base rates because it will unnecessarily mute the customer protections envisioned by this Commission when it designed the REST rules.

Q HOW WILL THE ROLL-IN TO BASE RATES OF REAC COSTS MUTE THE CUSTOMER COST PROTECTIONS IN THE REST RULES?

A First, splitting cost recovery of the subsidized renewable energy costs between base rates and the REAC rider will limit transparency for customers and policy makers of the true cost of developing renewable generation in Arizona. Many customers rely on transparent recording of renewable energy payments to the utility when accounting for their own internal renewable energy or carbon reduction goals. Second, rolling \$37.6 million into base rates will show an artificial reduction in the renewable costs included under the legislative REAC customer charge caps, which may have the unintended consequence of allowing APS even further increased cost recovery for renewable energy subsidization. Already the per-unit cost cap established in 2007 in the REST rules, \$0.004988/kWh, has increased 88% to \$0.009355/kWh in the current

[19] A.A.C. R 14-2-1816, Appendix A.

REAC tariff. Rolling costs into base rates may mute the realized per-unit cost increase over the next 10 years, or more, that the REST rules are in effect.

Q WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S PROPOSALS RELATED TO THE DSMAC AND REAC?

A I recommend APS's proposal to roll-in to base rates $37.6 million in REAC costs be rejected. This treatment will mute the customer protections envisioned by this Commission in its designing of the REST rules. My objection does not disallow the Company's full recovery of these costs, but simply makes clearer to ratepayers, investors, and policy makers the true full cost of complying with the Arizona renewable energy mandates.

I do not object to the Company's proposal to roll $10 million in DSMAC costs into base rates, as similar discrete customer cost caps do not exist, and the Company has indicated that the roll-in to base rates will be done on a revenue neutral basis for each customer class.[20]

IV.D. Rate Rider Schedule AG-1

Q PLEASE DESCRIBE THE COMPANY'S PROPOSALS RELATED TO RATE AG-1.

A The Company is proposing to eliminate the Alternative Generation Rate AG-1 option, which is a wheeling rate option for select commercial and industrial customers that were selected via lottery after the 2012 final order in APS's last base rate case. The AG-1 program was capped at 200 MW of total participation, and allows the participating customers to enter into contract for generation power supply from a non-utility electricity provider, but transmit the power through to the end-use customer

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[20] APS response to FEA 5.12.

using the APS transmission and distribution system. APS continues to charge the customer the otherwise applicable non-generation tariff charges, an AG-1 program fee, the individual customer's contract electricity supply rate established with the third-party supplier, plus 15% of the otherwise applicable capacity charge under APS base tariff rates deemed by APS a "reservation charge" for firm capacity on the APS system.

Q WHY DOES THE COMPANY PROPOSE ELIMINATING RATE AG-1?

A APS claims that it has experienced unrecovered costs totaling $24.4 million for 2012 through 2015, and does not wish to continue shifting these net losses onto other retail customers.[21] APS was granted authority in the Commission's Decision No. 75322 to defer the Rate AG-1 lost margins from June 30, 2016 through the rate effective date of the instant proceeding for recovery from all non-residential.[22]

Q DO YOU AGREE WITH THE COMPANY'S ESTIMATED UNRECOVERED RATE AG-1 PROGRAM COSTS?

A No. I do not agree with the Company's assumptions concerning lost, or stranded, production-related revenue nor its estimated savings from not providing power supply to the Rate AG-1 customers. First, APS has estimated the stranded production-related costs using the Company's current embedded unbundled tariff rates for generation,[23] which I have shown in my testimony to be collecting more than the proper allocated costs for several of the large customer classes. This has the effect

[21]Attachment LRS-06DR, page 4.
[22]Snook page 43, lines 16-20
[23]Attachment LRS-06DR, page 4.

of overstating the true unrecovered production costs caused by these discrete Rate AG-1 customers by more than 100%.[24]

Second, APS has understated the offsetting value of the fuel cost savings that APS receives as it is no longer incurring variable production expense to serve these customers. APS has used the authorized base cost of fuel rate in the last APS base rate case, multiplied by the Rate AG-1 annual sales, to determine fuel savings.[25] In reality, APS is able to avoid its marginal cost of fuel or purchased power energy, which is the cost of the last units of energy that would have been produced or purchased by APS in a given hour in order to serve the additional Rate AG-1 customers. By definition, marginal fuel costs are greater than the annual average fuel cost. APS's oversimplified calculation of the Rate AG-1 fuel cost savings also neglects to specifically account for the fixed or renewable power costs that the Company does not avoid because of Rate AG-1. APS should provide a more exact calculation of its true fuel and purchased power cost savings from the Rate AG-1 program.

Third, APS explained that its calculated off-system margin gained by selling to non-retail customers any energy made excess by not serving Rate AG-1 customers does not include the margin on excess capacity. APS's response to AECC 3.4 states:

> The projected off-system sales margins are based on the December 2015 forward curves for natural gas and power at the Palo Verde hub and the expected availability of generating resources that are both economic and not needed to serve native load demand.

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[24]Combining the AG-1 eligible classes in the COSS results, and comparing Company proposed rates to the required revenue plus the fair value increment shows that many classes are paying excess revenue beyond cost of service sufficient to cover the $55 million in lost revenue from AG-1 in the test year.

[25]APS response to FEA 6.5(b).

The calculation does not include the market value of 200 MW of excess generating capacity that is no longer needed to provide firm power supply to the Rate AG-1 customers. Benchmarking APS's marginal cost of production capacity at the cost of its recently acquired stake in Four Corners, the value of this capacity could reach $7.8 million.[26] The 200 MW is also needed to meet APS's target reserve margin, and its 2015 Form 10-K indicates "APS anticipates additional resources will be needed by 2017 in order to maintain its 15% planning reserve criteria."[27]

APS has simultaneously overstated the stranded production-related investment costs unrecovered from Rate AG-1 customers, and understated the marginal fuel cost savings and excess capacity sales revenue APS receives by not providing Rate AG-1 customers with power supply. The net effect is that APS's estimated $24.4 million Rate AG-1 program cost from 2012 through 2015 may be significantly overstated, and perhaps fully offset considering many classes' standard tariff production charges are set above cost of service.

Q IS APS REQUIRED TO MINIMIZE ITS UNRECOVERED COSTS FROM THE RATE AG-1 PROGRAM?

A Yes. The Commission's order in the last APS base rate case permitting creation of the Rate AG-1 program required APS to:

> make commercially reasonable efforts to eliminate or mitigate all unrecovered costs resulting from the experimental AG-1 program in this docket. If there are any lost fixed generation costs related to the AG-1 experimental rate, in its next general rate case, APS shall provide testimony that explains why it was unable to eliminate all lost fixed generation costs.[28]

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[26]APS paid approximately $4.2 million for a 108 MW stake in Four Corners in 2016.
[27]APS Form 10-K, page 13.
[28]Decision No. 73183, Exhibit A, Settlement Agreement, Paragraph 17.2.

APS's testimony in the instant proceeding does not explain why it was unable to eliminate all lost fixed generation costs, as ordered by the Commission. Mr. Snook's Direct Testimony and Attachment LRS_06DR do not adequately address that point. Further, APS's neglect to account for off-system sales of the 200 MW of capacity freed-up by the Rate AG-1 program does not meet the criterion that APS make commercially reasonable efforts to mitigate all of its unrecovered costs.

Q DO YOU SUPPORT THE COMPANY'S PROPOSAL TO ELIMINATE THE RATE AG-1 PROGRAM?

A No. I believe the Rate AG-1 program should continue, in an expanded capacity beyond the 200 MW current limit, so as to allow more than the eight current Rate AG-1 customers[29] the opportunity to manage more directly their generation supply costs via contracts with third-party suppliers. The Rate AG-1 program is obviously beneficial to the current customers, given that the program has been continually fully subscribed since its inception, and when reviewing the per-unit total present rates paid by Rate AG-1 customers as compared to the total rates paid by customers in the otherwise applicable standard tariff rate classes. Table 4 below shows this comparison, and Rate AG-1 customers are enjoying on average a 4% discount to the otherwise applicable APS tariff rate, even accounting for all Rate AG-1 fees charged under present rates.

[29]Decision No. 75322, page 7, line 28.

TABLE 4

Rate AG-1 Present Rates
Compared to Company Supply - Otherwise Applicable Tariff Rates

Rate Class	Adjusted MWh	Present Base Revenue ($000)	Present Revenue Rate ($/MWh)	Present Rate Discount Percent
E-32 M	3,138,247	305,191	$ 97.25	
E-32 M (AG-1)	43,488	3,634	$ 83.56	-14%
E-32 L	2,838,787	239,240	$ 84.28	
E-32 L (AG-1)	405,944	32,938	$ 81.14	-4%
E-32TOU L	240,589	20,381	$ 84.71	
E-32TOU (AG-1)	11,695	827	$ 70.71	-17%
E-34	710,025	50,469	$ 71.08	
E-34 (AG-1)	124,018	9,373	$ 75.58	6%
E-35	1,469,900	97,503	$ 66.33	
E-35 (AG-1)	465,141	28,956	$ 62.25	-6%
Weighted Average				**-4%**

Source: Schedule H-2, page 2 of 3

Q **WHAT DO YOU PROPOSE CONCERNING RATE AG-1?**

A I recommend that the Company provided a corrected calculation of the stranded costs through 2015 in its rebuttal testimony, reflecting the errors I have previously pointed out in my testimony. Any stranded costs that still remain should be shared on a 90/10 basis, with the Company funding 10% of the stranded cost, following the cost deferral order granted by the Commission in Decision No. 75322. The 90% remainder of the stranded cost value on a going-forward basis should be recovered from all non-residential customers, again per the Commission's prior order.

Q HOW DO YOU RESPOND TO THE COMPANY'S PROPOSAL TO CHARGE A 100% RESERVATION FEE, AS OPPOSED TO 15%, FOR GENERATION CAPACITY IN THE EVENT THE COMMISSION DOES NOT CANCEL THE RATE AG-1 PROGRAM?

A No reservation generation capacity charge is warranted, as Rate AG-1 customers are intended to be procuring firm power supply from their third-party supplier. Indeed, the tariff language in Rate AG-1 requires the Generation Service Provider to deliver firm power supply to APS on behalf of the Rate AG-1 customer. If APS is not receiving sufficient firm power supply for Rate AG-1 customers to account for transmission losses or the Commission-required generation reserve requirement, the Rate AG-1 tariff should be clarified to require the Generation Service Provider to gross up the necessary firm capacity amount by the appropriate factors. APS should not be permitted to charge Rate AG-1 customers for firm capacity, nor capacity reserves, at the utility's embedded generation rate. Rate AG-1 customers should have the opportunity to purchase their full firm capacity needs on the open market.

V. VALUE OF ROOFTOP SOLAR GENERATION

Q HAVE YOU REVIEWED THE COMPANY'S SUPPLEMENTAL TESTIMONY CONCERNING THE IMPACT OF THE COMMISSION'S VALUE OF SOLAR ORDER ON THE INSTANT PROCEEDING?

A Yes. Messrs. Burke and Miessner provided Supplemental Testimony filed on December 30, 2016 to comply with the Commission's December 20, 2016 Order in Docket No. E-0000000J-14-0023, the Value and Cost of Distribution Generation Proceeding. The Commission Order instructed Arizona utilities with currently pending base rate cases to calculate the amount to be paid for export energy generated by rooftop solar arrays using the Resource Comparison Proxy methodology ("RCP"). The RCP was developed within the Value and Cost of Distribution Generation Proceeding, and estimated in Mr. Burke's Supplemental Testimony at $0.11524/kWh.

Q HAS APS ADJUSTED ITS TARIFF RATES TO INCORPORATE THE CALCULATED RCP PAYMENT RATE?

A Yes. Mr. Miessner describes in his supplemental testimony that APS will pay the RCP value of export solar to customers taking service under Rate Rider EPR-6s, which is applicable only to customers who have on-site solar generation with a nameplate capacity of 100 kW-ac or less.

Q DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S PROPOSED INCLUSION OF THE RCP VALUE IN ITS TARIFFS?

A Yes, by including the RCP value payment rate only in its Rate Rider EPR-6s, it has created an arbitrary capacity maximum for rooftop solar customers that was not required in the Commission's Order in Docket No. E-0000000J-14-0023. I propose Rate Rider EPR-6s be adjusted to remove the 100 kW-ac nameplate capacity maximum, given that the export value of solar energy for even a 101 kW-ac array is not meaningfully different from the value of a 100 kW-ac array. Any future customer seeking to install a 101 kW-ac array, which would most likely include a larger commercial or industrial customer with significant rooftop space, would be ineligible for the Company's Rate Rider EPR-6s, and be placed instead on Rate Rider E-56R.

Rate Rider E-56R is designed to appropriately bill and compensate customers with any type of renewable energy generation facility greater than 100 kW installed behind the customer's meter. Rider E-56R was not redlined as part of APS's

Supplemental Testimony concerning the Value and Cost of Distribution Generation Proceeding. APS proposes in the instant proceeding to pay for export energy under Rate Rider E-56R at a seasonal energy rate that is capped at $0.04297/kWh for the on-peak summer period. This export rate paid to 101 kW-ac rooftop solar customers is only 37% of the rate paid to 100 kW-ac rooftop solar customers. Further, Rider E-56R requires customers to purchase Standby Distribution Capacity for an amount equal to the capacity of the on-site renewable generation, at the unbundled distribution rate of the customer's base rate schedule, a charge which is not assessed to customers under Rider EPR-6s.

Q SHOULD THERE BE A PROJECT CAPACITY SIZE CAP ON CUSTOMERS ELIGIBLE FOR THE RCP PAYMENT OF EXPORT ROOFTOP SOLAR ENERGY?

A Yes. The other requirement in Rider EPR-6s that the nameplate capacity must be less than 125% of a customer's average monthly kW demand over the prior 12 months is reasonable. The Commission ordered that this cap be placed on Arizona utilities' net energy metering rate offerings in development of the Commission's Net Metering Rules (A.A.C. R14-2-2301) instituted in 2009. I believe this requirement should be maintained in order to prevent abuse of the net metering incentive.

Q WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S PROPOSED PAYMENTS FOR EXPORT ENERGY FROM ROOFTOP SOLAR CUSTOMERS?

A I recommend the Company adjust its Rate Rider EPR-6s to remove the 100 kW-ac maximum limit, in order to provide all rooftop solar customers the appropriate payment rate calculated using the RCP method as ordered by the Commission in the Value and Cost of Distribution Generation Proceeding.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Amanda M. Alderson

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Amanda Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a Senior Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from the University of Illinois at Urbana-Champaign in 2008 where I received my Bachelor of Arts in Economics, with minor studies in Statistics and International Business. I earned my Masters of Business Administration Degree with a concentration in Logistics and Operations Management upon graduation from the University of Missouri-St. Louis in 2011.

I joined BAI in 2008 as an analyst. Then, in September 2011, I joined the consulting team of BAI.

I have worked on various issues including embedded and marginal cost of service studies, rate design, power procurement and portfolio management, contract negotiation and environmental and sustainability compliance management.

In the regulated arena, I have evaluated cost of service studies and rate designs proffered by other parties in cases for various utilities, including in Florida, Illinois, Indiana, Michigan, New Mexico, Quebec, Nova Scotia, and others. I have conducted bill audits, rate forecasts and tariff rate optimization studies. I have performed utility investment prudence reviews with respect to such items as fuel, purchased power and renewable energy investments.

I have also provided support to clients with facilities in deregulated markets, including drafting supply requests for proposals, evaluating supply bids, and auditing competitive supply bills. I have also prepared and presented to clients reports that monitor the electric market and recommend strategic hedging transactions.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA Production Cost Allocation Corrections

SUMMARY OF RESULTS	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
ELECTRIC PLANT IN SERVICE	15,326,435,253	12,962,340,167	2,364,095,086	12,962,340,167	8,099,051,086	4,554,642,478	122,239,266	133,850,295	52,557,042
GENERAL & INTANGIBLE PLANT	1,509,541,568	1,400,428,100	109,113,468	1,400,428,100	913,116,365	464,146,198	11,777,669	7,325,948	4,061,919
LESS: RESERVE FOR DEPRECIATION	(6,402,411,202)	(5,632,319,059)	(770,092,143)	(5,632,319,059)	(3,511,914,005)	(2,062,097,799)	(52,785,504)	(47,533,720)	(17,988,030)
OTHER DEFERRED CREDITS	(1,337,180,000)	(1,292,838,371)	(44,341,629)	(1,292,838,371)	(768,219,184)	(503,174,861)	(12,664,195)	(6,801,831)	(1,978,460)
WORKING CASH	(113,623,376)	(93,558,549)	(20,064,827)	(93,558,549)	(58,268,866)	(32,917,589)	(893,500)	(1,054,520)	(403,975)
MATERIALS, SUPPLIES & PREPAYMENTS	438,426,790	398,768,143	39,658,647	398,768,143	225,856,548	164,697,669	4,153,353	3,070,544	990,029
ACCUM. DEFERRED TAXES	(2,873,411,027)	(2,359,729,334)	(513,681,693)	(2,359,729,334)	(1,503,979,442)	(796,946,649)	(21,719,932)	(26,263,829)	(10,818,481)
REGULATORY ASSETS	310,940,000	250,199,222	60,740,778	250,199,222	181,817,468	63,623,483	1,701,159	1,762,326	1,294,787
DECOMMISSIONING FUND	735,196,000	731,225,942	3,970,058	731,225,942	434,549,532	285,200,677	7,291,629	3,632,160	551,943
MISCELLANEOUS DEFERRED DEBITS	121,338,000	113,265,656	8,072,344	113,265,656	71,286,870	40,082,726	1,006,098	594,776	295,186
OPEB	182,625,115	168,753,227	13,871,888	168,753,227	110,070,359	55,890,824	1,418,175	882,962	490,906
CUSTOMER ADVANCES	(115,609,383)	(94,903,242)	(20,706,141)	(94,903,242)	(49,850,247)	(44,764,969)	(138,265)	(149,058)	(683)
CUSTOMER DEPOSITS	(72,621,690)	(72,621,690)		(72,621,690)	(38,578,117)	(32,816,324)	(706,920)	(511,132)	(209,197)
PROFORMA ADJUSTMENTS	302,154,000	292,140,717	10,013,283	292,140,717	183,596,173	101,925,712	2,494,009	2,808,171	1,316,652
TOTAL RATE BASE	**8,011,800,046**	**6,771,160,929**	**1,240,649,119**	**6,771,160,929**	**4,288,514,539**	**2,317,801,636**	**63,173,042**	**71,813,082**	**30,168,819**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	2,909,647,523	2,865,563,427	44,084,096	2,865,563,427	1,468,282,584	1,338,700,733	29,014,733	20,979,131	8,586,247
PROFORMA TO BASE REVENUES FROM RATES	23,340,145	23,340,145		23,340,145	18,295,059	5,225,164	(275,293)	103,126	(7,912)
SURCHARGE & OTHER ELECTRIC REVENUES	582,709,014	570,735,507	11,973,507	570,735,507	316,626,510	243,272,570	7,471,258	2,579,858	785,311
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(412,607,651)	(412,186,408)	(421,243)	(412,186,408)	(236,557,673)	(167,694,771)	(5,668,781)	(1,688,665)	(578,518)
TOTAL OPERATING REVENUES	**3,103,089,031**	**3,047,452,871**	**55,636,359**	**3,047,452,871**	**1,566,646,481**	**1,419,503,696**	**30,541,917**	**21,973,450**	**8,787,128**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	1,804,920,730	1,968,494,902	(163,574,171)	1,968,494,902	1,043,343,244	889,418,604	23,728,615	9,530,645	2,473,794
ADMINISTRATIVE & GENERAL	193,799,761	176,678,975	17,120,787	176,678,975	115,813,168	57,912,664	1,473,481	946,786	532,876
DEPRECIATION & AMORT EXPENSE	456,219,756	402,496,860	53,722,896	402,496,860	252,267,709	141,405,047	3,731,763	3,614,227	1,478,115
AMORTIZATION ON GAIN	(4,626,993)	(4,601,933)	(25,060)	(4,601,933)	(2,729,002)	(1,800,581)	(45,991)	(22,882)	(3,477)
REGULATORY ASSETS	17,910,882	17,910,882		17,910,882	10,643,995	6,985,797	178,603	88,967	13,519
PROFORMA ADJUSTMENTS	(55,126,400)	(63,537,447)	8,411,047	(63,537,447)	(8,349,631)	(53,640,271)	(1,961,467)	259,069	155,052
TAXES OTHER THAN INCOME	171,499,317	139,384,353	32,114,964	139,384,353	88,501,094	47,275,162	1,289,515	1,833,384	685,199
INCOME TAX	258,174,789	224,356,180	33,818,609	224,356,180	69,976,067	148,859,126	1,809,650	2,363,897	1,347,439
PROFORMA INCOME TAX ADJUSTMENTS	(131,826,847)	(128,134,190)	(3,692,657)	(128,134,190)	(82,116,793)	(43,413,146)	(1,555,645)	(745,834)	(302,771)
TOTAL OPERATING EXPENSES	**2,710,944,993**	**2,733,048,581**	**(22,103,586)**	**2,733,048,581**	**1,487,349,652**	**1,193,002,402**	**28,648,523**	**17,668,258**	**6,379,747**
OPERATING INCOME	**392,144,038**	**314,404,090**	**77,738,945**	**314,404,090**	**79,296,829**	**226,501,294**	**1,893,394**	**4,305,192**	**2,407,381**
RATE OF RETURN (PRESENT)	**4.89%**	**4.64%**	**6.27%**	**4.64%**	**1.85%**	**9.77%**	**3.00%**	**6.01%**	**7.98%**
INDEX RATE OF RETURN (PRESENT)	**1.00**	**0.95**	**1.28**	**0.95**	**0.38**	**2.00**	**0.61**	**1.23**	**1.63**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA Production Cost Allocation Corrections

		GENERAL SERVICE									
SUMMARY OF RESULTS	TOTAL GENERAL SERVICE	E-20 (Church Rate)	E-32 TOU (0-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35
DEVELOPMENT OF RATE BASE											
ELECTRIC PLANT IN SERVICE	4,554,642,478	35,879,010	11,427,670	20,584,527	64,756,490	58,758,131	1,699,623,772	1,072,049,524	921,309,172	211,511,618	458,742,564
GENERAL & INTANGIBLE PLANT	464,146,198	3,096,645	1,201,647	2,129,615	6,436,253	4,973,372	183,186,887	101,103,699	90,080,364	21,831,237	50,306,479
LESS: RESERVE FOR DEPRECIATION	(2,002,097,799)	(15,470,138)	(4,994,616)	(9,037,865)	(28,494,203)	(25,311,933)	(742,135,274)	(466,327,998)	(404,726,918)	(96,092,278)	(210,506,576)
OTHER DEFERRED CREDITS	(503,174,691)	(3,176,214)	(1,251,919)	(2,344,793)	(7,577,244)	(5,563,302)	(174,838,524)	(115,346,964)	(105,632,714)	(25,812,080)	(61,620,927)
WORKING CASH	(32,917,669)	(269,576)	(82,116)	(147,940)	(467,074)	(440,091)	(12,247,505)	(7,841,230)	(6,673,444)	(1,517,859)	(3,230,853)
MATERIALS, SUPPLIES & PREPAYMENTS	164,697,669	859,854	422,710	794,989	2,609,248	1,654,020	54,660,014	38,122,227	35,861,386	8,596,074	21,117,046
ACCUM. DEFERRED TAXES	(796,946,640)	(6,077,659)	(2,000,773)	(3,558,606)	(11,039,560)	(10,686,404)	(306,382,300)	(187,893,232)	(158,196,207)	(35,716,544)	(74,797,360)
REGULATORY ASSETS	63,623,483	545,521	171,513	275,748	714,988	743,620	31,108,115	12,939,718	10,319,839	2,289,123	4,515,297
DECOMMISSIONING FUND	285,200,677	2,188,437	687,285	1,281,536	4,183,938	3,652,953	98,600,144	67,083,645	59,438,957	14,638,660	33,445,123
MISCELLANEOUS DEFERRED DEBITS	40,082,726	238,784	103,947	187,843	582,662	406,307	15,032,013	8,824,866	8,076,128	1,950,371	4,679,805
OPEB	55,890,824	372,625	144,745	256,465	774,820	598,328	22,071,526	12,169,993	10,843,402	2,603,520	6,055,400
CUSTOMER ADVANCES	(44,764,989)	(141,280)	(139,627)	(226,524)	(697,879)	(375,081)	(17,171,511)	(10,472,745)	(9,098,276)	(1,911,601)	(4,538,363)
CUSTOMER DEPOSITS	(32,616,324)	(101,767)	(101,916)	(166,738)	(508,722)	(272,140)	(12,521,197)	(7,630,243)	(6,620,434)	(1,390,579)	(3,302,587)
PROFORMA ADJUSTMENTS	101,925,712	726,988	262,993	468,079	1,441,798	1,194,666	39,266,492	23,260,994	20,296,055	4,647,718	10,359,928
TOTAL RATE BASE	**2,317,891,636**	**18,071,328**	**5,841,540**	**10,494,234**	**32,715,525**	**29,333,446**	**878,252,653**	**540,042,255**	**466,288,306**	**106,427,380**	**231,224,968**
DEVELOPMENT OF RETURN											
BASE REVENUES FROM RATES	1,338,700,733	4,176,910	4,183,101	6,843,561	20,879,912	11,169,689	513,918,578	313,174,826	271,728,356	57,074,785	135,551,017
PROFORMA TO BASE REVENUES FROM RATES	5,225,164	(107,647)	(15,924)	(69,241)	(334,450)	175,286	(2,421,490)	(4,532,152)	2,082,092	2,766,532	7,682,056
SURCHARGE & OTHER ELECTRIC REVENUES	243,272,570	1,080,040	794,726	1,184,024	3,141,198	2,347,068	103,074,992	57,784,217	42,240,994	8,760,280	21,865,031
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(167,594,771)	(831,475)	(600,842)	(802,479)	(1,875,640)	(1,753,226)	(80,163,046)	(40,247,364)	(24,894,779)	(5,540,408)	(10,976,510)
TOTAL OPERATING REVENUES	**1,419,603,696**	**4,317,828**	**4,361,161**	**7,155,864**	**21,811,020**	**11,938,817**	**534,409,051**	**326,179,528**	**291,156,663**	**64,052,189**	**154,121,595**
OPERATING EXPENSES											
OPERATION & MAINTENANCE	889,418,604	3,716,421	2,370,147	4,314,672	14,008,491	8,041,141	299,908,580	204,806,787	191,249,248	45,962,109	115,039,006
ADMINISTRATIVE & GENERAL	57,912,664	391,904	150,079	265,032	797,201	624,691	23,054,380	12,594,649	11,172,043	2,675,339	6,187,346
DEPRECIATION & AMORT EXPENSE	141,405,047	1,048,365	357,655	644,381	2,018,088	1,727,203	52,921,068	32,711,099	28,530,249	6,641,891	14,805,049
AMORTIZATION ON GAIN	(1,800,581)	(13,687)	(4,345)	(8,107)	(26,489)	(22,922)	(621,071)	(423,373)	(375,914)	(92,580)	(212,093)
REGULATORY ASSETS	6,985,797	53,604	16,835	31,390	102,483	89,477	2,415,143	1,643,168	1,455,917	358,564	819,216
PROFORMA ADJUSTMENTS	(53,640,271)	(133,596)	(222,461)	(270,398)	(756,166)	(261,910)	(27,246,306)	(13,417,599)	(9,287,093)	(653,622)	(1,381,128)
TAXES OTHER THAN INCOME	47,275,162	382,023	119,764	213,183	661,837	618,446	18,112,874	11,137,510	9,440,218	2,116,235	4,473,071
INCOME TAX	148,859,126	(273,855)	701,358	891,178	2,190,141	685,040	77,005,927	36,855,350	23,765,888	2,738,789	4,299,310
PROFORMA INCOME TAX ADJUSTMENTS	(43,413,145)	(311,970)	(157,998)	(240,108)	(583,959)	(518,340)	(22,027,263)	(12,442,762)	(5,473,611)	(863,549)	(793,566)
TOTAL OPERATING EXPENSES	**1,193,002,402**	**4,861,220**	**3,331,035**	**5,841,223**	**18,411,827**	**10,982,825**	**423,523,331**	**273,464,829**	**250,476,946**	**58,873,175**	**143,236,192**
OPERATING INCOME	**226,601,294**	**(543,392)**	**1,030,126**	**1,314,641**	**3,399,193**	**955,992**	**110,885,720**	**52,714,698**	**40,679,718**	**5,179,014**	**10,885,403**
RATE OF RETURN (PRESENT)	**9.77%**	**(3.01%)**	**17.63%**	**12.53%**	**10.39%**	**3.26%**	**12.63%**	**9.76%**	**8.74%**	**4.87%**	**4.71%**
INDEX RATE OF RETURN (PRESENT)	**2.00**	**(0.61)**	**3.60**	**2.56**	**2.12**	**0.67**	**2.58**	**1.99**	**1.79**	**0.99**	**0.96**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA Production Cost Allocation Corrections

SUMMARY OF RESULTS	TOTAL RESIDENTIAL	RESIDENTIAL				
		Solar Energy Rates (E-12, ET-1 & ET-2)	Solar Demand Rates (ECT-1 & ECT-2)	E-12	ET-1 & ET-2	ECT-1 & ECT-2
DEVELOPMENT OF RATE BASE						
ELECTRIC PLANT IN SERVICE	8,099,051,086	359,317,931	18,729,906	2,181,586,792	3,967,361,127	1,572,055,331
GENERAL & INTANGIBLE PLANT	913,116,365	47,816,295	2,225,148	286,622,522	420,071,890	156,380,511
LESS: RESERVE FOR DEPRECIATION	(3,511,914,006)	(159,178,281)	(8,201,318)	(956,681,871)	(1,711,729,418)	(676,123,118)
OTHER DEFERRED CREDITS	(768,219,184)	(35,053,127)	(1,827,958)	(212,176,542)	(370,938,142)	(148,223,415)
WORKING CASH	(56,288,966)	(2,511,313)	(133,480)	(15,263,080)	(28,854,269)	(11,526,704)
MATERIALS, SUPPLIES & PREPAYMENTS	225,856,548	9,723,164	533,017	61,674,894	109,299,722	44,625,752
ACCUM. DEFERRED TAXES	(1,503,979,442)	(67,478,168)	(3,469,949)	(408,318,948)	(735,604,774)	(289,107,583)
REGULATORY ASSETS	181,817,468	10,423,768	446,656	61,820,875	80,998,943	28,127,225
DECOMMISSIONING FUND	434,549,532	18,565,663	1,012,884	108,810,613	217,388,521	88,771,851
MISCELLANEOUS DEFERRED DEBITS	71,286,870	3,631,865	173,502	22,038,643	32,952,466	12,490,395
OPEB	110,070,359	5,767,796	268,270	34,575,849	50,620,945	18,837,500
CUSTOMER ADVANCES	(49,850,247)	(679,199)	(76,618)	(15,137,036)	(24,414,448)	(9,542,946)
CUSTOMER DEPOSITS	(36,578,117)	(513,370)	(58,959)	(11,736,686)	(18,889,435)	(7,379,687)
PROFORMA ADJUSTMENTS	183,596,173	8,837,439	432,202	53,914,535	87,104,240	33,307,757
TOTAL RATE BASE	**4,288,514,839**	**196,670,442**	**10,063,303**	**1,191,730,581**	**2,075,367,346**	**812,692,868**
DEVELOPMENT OF RETURN						
BASE REVENUES FROM RATES	1,468,282,584	19,538,868	2,243,969	446,697,353	718,931,632	280,870,762
PROFORMA TO BASE REVENUES FROM RATES	18,295,059	3,192,150	122,765	8,426,843	5,908,510	844,792
SURCHARGE & OTHER ELECTRIC REVENUES	316,626,510	7,335,405	520,527	95,962,097	152,180,429	60,628,053
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(236,557,673)	(4,087,358)	(327,941)	(74,221,765)	(113,853,421)	(44,287,189)
TOTAL OPERATING REVENUES	**1,566,646,481**	**25,979,065**	**2,559,319**	**476,864,527**	**763,367,150**	**297,876,418**
OPERATING EXPENSES						
OPERATION & MAINTENANCE	1,043,343,244	23,269,517	1,536,180	296,585,616	509,042,895	212,909,035
ADMINISTRATIVE & GENERAL	115,813,168	6,086,865	282,200	36,459,360	53,226,590	19,758,152
DEPRECIATION & AMORT EXPENSE	252,267,709	11,640,073	591,459	70,592,332	121,750,702	47,693,143
AMORTIZATION ON GAIN	(2,729,002)	(116,504)	(6,363)	(683,014)	(1,364,650)	(557,570)
REGULATORY ASSETS	10,643,995	454,753	24,810	2,665,242	5,324,784	2,174,406
PROFORMA ADJUSTMENTS	(6,349,931)	1,920,634	68,473	(5,627,017)	(3,634,066)	(877,834)
TAXES OTHER THAN INCOME	88,501,094	3,966,033	204,165	24,214,339	43,159,527	16,957,029
INCOME TAX	69,976,067	(8,666,076)	(33,095)	33,125,989	36,090,023	9,459,226
PROFORMA INCOME TAX ADJUSTMENTS	(82,116,793)	(1,028,775)	(105,279)	(23,580,576)	(40,731,669)	(16,670,495)
TOTAL OPERATING EXPENSES	**1,487,349,652**	**37,526,522**	**2,562,549**	**433,551,372**	**722,864,115**	**290,845,093**
OPERATING INCOME	**79,296,829**	**(11,547,456)**	**(3,230)**	**43,313,155**	**40,503,035**	**7,031,326**
RATE OF RETURN (PRESENT)	**1.85%**	**(5.81%)**	**(0.03%)**	**3.63%**	**1.95%**	**0.87%**
INDEX RATE OF RETURN (PRESENT)	**0.38**	**(1.19)**	**(0.01)**	**0.74**	**0.40**	**0.18**

ARIZONA PUBLIC SERVICE COMPANY
Development of FEA Allocation Factors for FERC Accounts 364-368

DESCRIPTION	ALLOCATOR		ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
364 Poles, Towers, and Fixtures		Split*									
Primary	*DEMDIST2 (NEW)*		442,954,584	442,954,584		442,954,584	348,849,651	89,039,489	1,924,999	1,069,539	2,070,907
Demand	DEMDIST2	36%	159,463,650	159,463,650		159,463,650	98,271,661	58,692,191	1,581,998	796,794	121,006
Customer	CUSTNUM_A	64%	283,490,934	283,490,934		283,490,934	250,577,989	30,347,298	343,001	272,745	1,949,901
Secondary	*DEMDIST3 (NEW)*		150,154,007	150,154,007		150,154,007	149,011,373			362,154	780,480
Demand	DEMDIST3	36%	54,055,442	54,055,442		54,055,442	53,757,716			258,474	39,252
Customer	CUSTNUM_S	64%	96,098,564	96,098,564		96,098,564	95,253,657			103,680	741,227
365 Overhead Conductors and Devices											
Primary	*DEMDIST2 (NEW)*		265,214,406	265,214,406		265,214,406	177,638,281	83,770,016	2,169,077	1,111,192	525,841
Demand	DEMDIST2	80%	212,171,525	212,171,525		212,171,525	130,753,612	78,091,851	2,104,899	1,060,160	161,003
Customer	CUSTNUM_A	20%	53,042,881	53,042,881		53,042,881	46,884,669	5,678,164	64,178	51,032	364,838
Secondary	*DEMDIST3 (NEW)*		89,903,135	89,903,135		89,903,135	89,348,913			363,307	190,915
Demand	DEMDIST3	80%	71,922,508	71,922,508		71,922,508	71,526,373			343,908	52,227
Customer	CUSTNUM_S	20%	17,980,627	17,980,627		17,980,627	17,822,540			19,399	138,688
Accounts 364 & 365											
Primary	***DEMDIST2 (NEW)***		708,168,990	708,168,990		708,168,990	526,487,931	172,809,505	4,094,075	2,180,731	2,596,749
Secondary	***DEMDIST3 (NEW)***		240,057,142	240,057,142		240,057,142	238,360,286			725,461	971,394
Total Accounts 364 & 365			948,226,132	948,226,132		948,226,132	764,848,217	172,809,505	4,094,075	2,906,192	3,568,143
366 Underground Conduit											
Primary	*DEMDIST4 (NEW)*		685,513,670	685,513,670		685,513,670	605,926,386	73,383,256	829,416	659,528	4,715,084
Demand	DEMDIST4	0%									
Customer	CUSTNUM_A	100%	685,513,670	685,513,670		685,513,670	605,926,386	73,383,256	829,416	659,528	4,715,084
367 Underground Conductors and Devices											
Primary	*DEMDIST4 (NEW)*		1,382,141,872	1,382,141,872		1,382,141,872	1,003,428,229	360,801,656	8,775,639	4,619,834	4,516,515
Demand	DEMDIST4	59%	815,463,704	815,463,704		815,463,704	502,540,691	300,139,570	8,090,005	4,074,636	618,802
Customer	CUSTNUM_A	41%	566,678,167	566,678,167		566,678,167	500,887,537	60,662,086	685,634	545,197	3,897,713
Secondary	*DEMDIST5 (NEW)*		264,239,199	264,239,199		264,239,199	262,428,009			862,349	948,841
Demand	DEMDIST5	59%	155,901,127	155,901,127		155,901,127	155,042,456			745,464	113,208
Customer	CUSTNUM_S	41%	108,338,072	108,338,072		108,338,072	107,385,554			116,885	835,633
Accounts 366 & 367											
Primary	***DEMDIST4 (NEW)***		2,067,655,542	2,067,655,542		2,067,655,542	1,609,354,614	434,184,912	9,605,055	5,279,362	9,231,599
Secondary	***DEMDIST5 (NEW)***		264,239,199	264,239,199		264,239,199	262,428,009			862,349	948,841
Total Accounts 366 & 367			2,331,894,741	2,331,894,741		2,331,894,741	1,871,782,623	434,184,912	9,605,055	6,141,711	10,180,440
368 Line Transformers											
OH Line Transformers	***DEMDIST6 (NEW)***		165,632,064	165,632,064		165,632,064	129,014,400	34,135,725	1,650,247	489,507	342,185
Demand	DEMDIST6	76%	125,880,368	125,880,368		125,880,368	93,847,426	29,911,075	1,602,109	451,229	68,529
Customer	CUSTNUM_S2	24%	39,751,695	39,751,695		39,751,695	35,166,974	4,224,650	48,138	38,278	273,656
UG Line Transformers	***DEMDIST7 (NEW)***		667,823,019	667,823,019		667,823,019	490,098,273	168,396,317	6,142,097	1,829,487	1,356,845
Demand	DEMDIST7	76%	507,545,495	507,545,495		507,545,495	348,428,769	151,238,838	5,948,174	1,675,285	254,428
Customer	CUSTNUM_A	24%	160,277,525	160,277,525		160,277,525	141,669,503	17,157,479	193,923	154,202	1,102,417
Total Account 368			833,455,083	833,455,083		833,455,083	619,112,672	202,532,043	7,792,344	2,318,994	1,699,030

* Source: Tucson Electric Power Company, Class Cost of Service Study - Allocation Factors, Schedule G-7, Sheet 3 of 9

ARIZONA PUBLIC SERVICE COMPANY
Development of FEA Allocation Factors for FERC Accounts 364-368

DESCRIPTION	ALLOCATOR	Split*	TOTAL GENERAL SERVICE	E-20 (Church Rate)	E-32 TOU (0-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35
			GENERAL SERVICE										
364 Poles, Towers, and Fixtures													
Primary	*DEMDIST2 (NEW)*		89,039,489	610,197	235,410	286,951	871,424	861,705	50,543,466	15,460,563	12,705,575	2,704,309	4,759,887
Demand	DEMDIST2	36%	58,692,191	514,394	145,756	269,682	858,414	832,846	21,673,674	14,459,711	12,490,076	2,697,686	4,749,952
Customer	CUSTNUM_A	64%	30,347,298	95,804	89,653	17,268	13,010	28,859	28,869,792	1,000,853	215,499	6,623	9,935
Secondary	*DEMDIST3 (NEW)*												
Demand	DEMDIST3	36%											
Customer	CUSTNUM_S	64%											
365 Overhead Conductors and Devices													
Primary	*DEMDIST2 (NEW)*		83,770,016	702,343	210,708	362,052	1,144,582	1,113,528	34,239,236	19,426,376	16,658,770	3,590,597	6,321,823
Demand	DEMDIST2	80%	78,091,851	684,417	193,933	358,821	1,142,147	1,108,128	28,837,522	19,239,111	16,618,449	3,589,358	6,319,965
Customer	CUSTNUM_A	20%	5,678,164	17,925	16,775	3,231	2,434	5,400	5,401,714	187,266	40,321	1,239	1,859
Secondary	*DEMDIST3 (NEW)*												
Demand	DEMDIST3	80%											
Customer	CUSTNUM_S	20%											
Accounts 364 & 365													
Primary	***DEMDIST2 (NEW)***		172,809,505	1,312,540	446,118	649,003	2,016,006	1,975,233	84,782,702	34,886,940	29,364,345	6,294,907	11,081,711
Secondary	***DEMDIST3 (NEW)***												
Total Accounts 364 & 365			172,809,505	1,312,540	446,118	649,003	2,016,006	1,975,233	84,782,702	34,886,940	29,364,345	6,294,907	11,081,711
366 Underground Conduit													
Primary	*DEMDIST4 (NEW)*		73,383,256	231,664	216,792	41,757	31,461	69,785	69,810,477	2,420,177	521,102	16,016	24,024
Demand	DEMDIST4	0%											
Customer	CUSTNUM_A	100%	73,383,256	231,664	216,792	41,757	31,461	69,785	69,810,477	2,420,177	521,102	16,016	24,024
367 Underground Conductors and Devices													
Primary	*DEMDIST4 (NEW)*		360,801,656	2,822,006	924,578	1,413,617	4,415,756	4,316,687	168,543,286	75,944,564	64,302,401	13,808,640	24,310,121
Demand	DEMDIST4	59%	300,139,570	2,630,501	745,367	1,379,099	4,389,749	4,258,999	110,834,629	73,943,931	63,871,633	13,795,401	24,290,261
Customer	CUSTNUM_A	41%	60,662,086	191,505	179,211	34,518	26,007	57,688	57,708,657	2,000,634	430,767	13,240	19,860
Secondary	*DEMDIST5 (NEW)*												
Demand	DEMDIST5	59%											
Customer	CUSTNUM_S	41%											
Accounts 366 & 367													
Primary	***DEMDIST4 (NEW)***		434,184,912	3,053,671	1,141,370	1,455,374	4,447,216	4,386,472	238,353,763	78,364,742	64,823,503	13,824,657	24,334,145
Secondary	***DEMDIST5 (NEW)***												
Total Accounts 366 & 367			434,184,912	3,053,671	1,141,370	1,455,374	4,447,216	4,386,472	238,353,763	78,364,742	64,823,503	13,824,657	24,334,145
368 Line Transformers													
OH Line Transformers	***DEMDIST6 (NEW)***		34,135,725	369,818	142,509	191,553		605,875	22,224,294	10,601,676			
Demand	DEMDIST6	76%	29,911,075	356,372	129,927	189,130		601,825	18,172,609	10,461,213			
Customer	CUSTNUM_S2	24%	4,224,650	13,445	12,582	2,423		4,050	4,051,686	140,463			
UG Line Transformers	***DEMDIST7 (NEW)***		168,396,317	1,377,274	533,069	711,948	2,172,041	2,250,721	83,791,862	39,405,357	27,955,277	2,169,325	8,029,444
Demand	DEMDIST7	76%	151,238,838	1,323,109	482,381	702,185	2,164,685	2,234,405	67,469,721	38,839,504	27,833,440	2,165,581	8,023,827
Customer	CUSTNUM_A	24%	17,157,479	54,165	50,687	9,763	7,356	16,316	16,322,141	565,853	121,837	3,745	5,617
Total Account 368			202,532,043	1,747,092	675,578	903,501	2,172,041	2,856,596	106,016,156	50,007,033	27,955,277	2,169,325	8,029,444

* Source: Tucson Electric Power Company, Class Cost of Service Study - Allocatior

ARIZONA PUBLIC SERVICE COMPANY
Development of FEA Allocation Factors for FERC Accounts 364-368

				RESIDENTIAL				
DESCRIPTION	ALLOCATOR		TOTAL RESIDENTIAL	Solar Energy Rates (E-12, ET-1 & ET-2)	Solar Demand Rates (ECT-1 & ECT-2)	E-12	ET-1 & ET-2	ECT-1 & ECT-2
364 Poles, Towers, and Fixtures		Split*						
Primary	*DEMDIST2 (NEW)*		348,849,651	12,741,968	538,420	136,377,180	151,019,033	48,173,049
Demand	DEMDIST2	36%	98,271,661	4,228,923	228,300	24,407,500	49,357,595	20,049,343
Customer	CUSTNUM_A	64%	250,577,989	8,513,045	310,120	111,969,679	101,661,438	28,123,706
Secondary	*DEMDIST3 (NEW)*		149,011,373	5,300,142	224,255	59,215,365	64,171,318	20,100,293
Demand	DEMDIST3	36%	53,757,716	2,064,029	106,367	16,651,684	25,526,169	9,409,466
Customer	CUSTNUM_S	64%	95,253,657	3,236,113	117,888	42,563,680	38,645,149	10,690,827
365 Overhead Conductors and Devices								
Primary	*DEMDIST2 (NEW)*		177,638,281	7,219,561	361,786	53,425,175	84,693,345	31,938,414
Demand	DEMDIST2	80%	130,753,612	5,626,719	303,760	32,474,966	65,671,870	26,676,297
Customer	CUSTNUM_A	20%	46,884,669	1,592,843	58,025	20,950,209	19,021,475	5,262,117
Secondary	*DEMDIST3 (NEW)*		89,348,913	3,351,754	163,582	30,119,527	41,194,133	14,519,917
Demand	DEMDIST3	80%	71,526,373	2,746,257	141,525	22,155,603	33,963,390	12,519,598
Customer	CUSTNUM_S	20%	17,822,540	605,496	22,058	7,963,924	7,230,743	2,000,319
Accounts 364 & 365								
Primary	***DEMDIST2 (NEW)***		526,487,931	19,961,530	900,206	189,802,355	235,712,378	80,111,463
Secondary	***DEMDIST3 (NEW)***		238,360,286	8,651,896	387,837	89,334,891	105,365,452	34,620,210
Total Accounts 364 & 365			764,848,217	28,613,426	1,288,042	279,137,246	341,077,830	114,731,673
366 Underground Conduit								
Primary	*DEMDIST4 (NEW)*		605,926,386	20,585,522	749,906	270,755,557	245,829,046	68,006,355
Demand	DEMDIST4	0%						
Customer	CUSTNUM_A	100%	605,926,386	20,585,522	749,906	270,755,557	245,829,046	68,006,355
367 Underground Conductors and Devices								
Primary	*DEMDIST4 (NEW)*		1,003,428,229	38,642,798	1,787,386	348,634,251	455,618,369	158,745,424
Demand	DEMDIST4	59%	502,540,691	21,625,828	1,167,478	124,814,845	252,404,401	102,528,140
Customer	CUSTNUM_A	41%	500,887,537	17,016,970	619,908	223,819,407	203,213,968	56,217,284
Secondary	*DEMDIST5 (NEW)*		262,428,009	9,601,138	439,675	96,009,835	117,187,096	39,190,266
Demand	DEMDIST5	59%	155,042,456	5,952,860	306,772	48,025,069	73,619,942	27,137,812
Customer	CUSTNUM_S	41%	107,385,554	3,648,278	132,902	47,984,765	43,567,154	12,052,454
Accounts 366 & 367								
Primary	***DEMDIST4 (NEW)***		1,609,354,614	59,228,320	2,537,292	619,389,808	701,447,414	226,751,779
Secondary	***DEMDIST5 (NEW)***		262,428,009	9,601,138	439,675	96,009,835	117,187,096	39,190,266
Total Accounts 366 & 367			1,871,782,623	68,829,458	2,976,967	715,399,643	818,634,510	265,942,045
368 Line Transformers								
OH Line Transformers	***DEMDIST6 (NEW)***		129,014,400	4,798,023	229,215	44,783,856	58,829,777	20,373,530
Demand	DEMDIST6	76%	93,847,426	3,603,273	185,691	29,069,647	44,562,262	16,426,553
Customer	CUSTNUM_S2	24%	35,166,974	1,194,750	43,523	15,714,208	14,267,515	3,946,977
UG Line Transformers	***DEMDIST7 (NEW)***		490,098,273	18,190,956	864,752	171,231,720	222,923,408	76,887,437
Demand	DEMDIST7	76%	348,428,769	13,377,928	689,419	107,927,322	165,446,989	60,387,112
Customer	CUSTNUM_A	24%	141,669,503	4,813,028	175,333	63,304,398	57,476,419	15,900,325
Total Account 368			619,112,672	22,988,979	1,093,966	216,015,576	281,753,185	97,260,967

* Source: Tucson Electric Power Company, Class Cost of Service Study - Allocatior

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA Corrected Distribution Cost Allocation - MDS

SUMMARY OF RESULTS	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
ELECTRIC PLANT IN SERVICE	15,326,435,253	12,962,340,167	2,364,095,086	12,962,340,167	8,539,219,424	4,125,619,728	106,444,901	126,067,867	64,988,247
GENERAL & INTANGIBLE PLANT	1,509,541,568	1,400,428,100	109,113,468	1,400,428,100	924,796,954	452,753,663	11,360,846	7,099,284	4,417,353
LESS: RESERVE FOR DEPRECIATION	(6,402,411,202)	(5,632,319,059)	(770,092,143)	(5,632,319,059)	(3,640,979,053)	(1,876,296,840)	(48,154,361)	(46,239,865)	(21,648,939)
OTHER DEFERRED CREDITS	(1,337,180,000)	(1,292,838,371)	(44,341,629)	(1,292,838,371)	(772,741,355)	(499,764,758)	(12,502,603)	(6,715,977)	(2,113,677)
WORKING CASH	(113,623,376)	(93,558,549)	(20,064,827)	(93,558,549)	(61,929,353)	(29,369,467)	(762,845)	(990,372)	(506,512)
MATERIALS, SUPPLIES & PREPAYMENTS	438,426,790	398,768,143	39,658,647	398,768,143	232,473,726	158,247,903	3,915,954	2,953,177	1,177,382
ACCUM. DEFERRED TAXES	(2,873,411,027)	(2,359,729,334)	(513,681,693)	(2,359,729,334)	(1,596,732,865)	(706,541,765)	(18,391,749)	(24,623,511)	(13,439,504)
REGULATORY ASSETS	310,940,000	250,199,222	60,740,778	250,199,222	187,906,442	57,686,546	1,483,311	1,649,074	1,473,849
DECOMMISSIONING FUND	735,196,000	731,225,942	3,970,058	731,225,942	434,549,532	285,200,677	7,291,629	3,632,160	551,943
MISCELLANEOUS DEFERRED DEBITS	121,338,000	113,265,656	8,072,344	113,265,656	72,097,974	39,291,625	977,154	579,036	319,867
OPEB	182,625,115	168,753,227	13,871,888	168,753,227	111,483,483	54,512,549	1,367,747	855,541	533,907
CUSTOMER ADVANCES	(115,609,383)	(94,903,242)	(20,706,141)	(94,903,242)	(49,850,247)	(44,764,989)	(138,265)	(149,058)	(683)
CUSTOMER DEPOSITS	(72,621,690)	(72,621,690)		(72,621,690)	(38,578,117)	(32,816,324)	(706,920)	(511,132)	(209,197)
PROFORMA ADJUSTMENTS	302,154,000	292,140,717	10,013,283	292,140,717	193,270,815	92,495,373	2,147,058	2,635,369	1,592,102
TOTAL RATE BASE	**8,011,800,048**	**6,771,150,929**	**1,240,649,119**	**6,771,150,929**	**4,534,987,420**	**2,077,453,921**	**54,331,859**	**67,241,592**	**37,136,137**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	2,909,647,523	2,865,563,427	44,084,096	2,865,563,427	1,468,282,584	1,338,700,733	29,014,733	20,979,131	8,586,247
PROFORMA TO BASE REVENUES FROM RATES	23,340,145	23,340,145		23,340,145	18,295,059	5,225,164	(275,293)	103,126	(7,912)
SURCHARGE & OTHER ELECTRIC REVENUES	582,709,014	570,735,507	11,973,507	570,735,507	318,341,202	241,601,124	7,410,721	2,550,304	832,156
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(412,607,651)	(412,186,408)	(421,243)	(412,186,408)	(236,870,204)	(167,390,153)	(5,657,567)	(1,683,140)	(585,345)
TOTAL OPERATING REVENUES	**3,103,089,031**	**3,047,452,871**	**55,636,359**	**3,047,452,871**	**1,568,048,642**	**1,418,136,867**	**30,492,595**	**21,949,421**	**8,825,146**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	1,804,920,730	1,968,657,998	(163,737,268)	1,968,657,998	1,020,043,692	913,610,715	23,199,435	9,198,001	2,606,155
ADMINISTRATIVE & GENERAL	193,799,761	176,678,975	17,120,787	176,678,975	117,457,485	56,308,993	1,414,774	915,129	582,593
DEPRECIATION & AMORT EXPENSE	456,219,756	402,496,860	53,722,896	402,496,860	263,027,757	130,917,006	3,345,705	3,422,687	1,783,706
AMORTIZATION ON GAIN	(4,626,993)	(4,601,933)	(25,060)	(4,601,933)	(2,729,002)	(1,800,561)	(45,891)	(22,882)	(3,477)
REGULATORY ASSETS	17,910,882	17,910,882		17,910,882	10,643,995	6,985,797	178,603	88,967	13,519
PROFORMA ADJUSTMENTS	(55,126,400)	(63,537,447)	8,411,047	(63,537,447)	(5,151,262)	(56,757,946)	(2,076,235)	202,523	245,374
TAXES OTHER THAN INCOME	171,499,317	139,384,353	32,114,964	139,384,353	94,471,605	41,455,832	1,075,277	1,527,822	853,817
INCOME TAX	258,174,789	224,294,040	33,880,749	224,294,040	70,542,641	147,738,669	2,313,834	2,641,530	1,057,366
PROFORMA INCOME TAX ADJUSTMENTS	(131,826,847)	(128,134,190)	(3,692,657)	(128,134,190)	(63,538,195)	(42,027,729)	(1,504,645)	(720,591)	(342,929)
TOTAL OPERATING EXPENSES	**2,710,944,995**	**2,733,149,538**	**(22,204,543)**	**2,733,149,538**	**1,484,768,715**	**1,196,430,854**	**27,900,757**	**17,253,086**	**6,796,125**
OPERATING INCOME	**392,144,036**	**314,303,133**	**77,840,902**	**314,303,133**	**83,279,928**	**221,706,014**	**2,591,838**	**4,696,335**	**2,029,021**
RATE OF RETURN (PRESENT)	**4.89%**	**4.64%**	**6.27%**	**4.64%**	**1.84%**	**10.67%**	**4.77%**	**6.98%**	**5.46%**
INDEX RATE OF RETURN (PRESENT)	**1.00**	**0.95**	**1.28**	**0.95**	**0.38**	**2.18**	**0.97**	**1.43**	**1.12**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA Corrected Distribution Cost Allocation - MDS

		GENERAL SERVICE									
SUMMARY OF RESULTS	TOTAL GENERAL SERVICE	E-20 (Church Rate)	E-32 TOU (0-100 KW)	E-32 TOU (101-400 KW)	E-32 TOU (401+ KW)	School TOU	E-30, E-32 (0-100 KW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35
DEVELOPMENT OF RATE BASE											
ELECTRIC PLANT IN SERVICE	4,125,619,728	30,876,141	10,412,858	17,723,154	55,561,657	49,720,556	1,661,266,187	918,687,398	788,866,327	183,835,560	408,669,888
GENERAL & INTANGIBLE PLANT	452,753,663	2,961,598	1,175,500	2,052,030	6,183,930	4,728,372	182,498,666	96,951,879	86,431,844	20,853,390	48,916,454
LESS: RESERVE FOR DEPRECIATION	(1,876,295,840)	(14,001,756)	(4,697,466)	(8,197,811)	(25,793,243)	(22,658,635)	(731,082,191)	(421,306,563)	(365,815,443)	(86,953,635)	(195,790,108)
OTHER DEFERRED CREDITS	(498,764,758)	(3,124,146)	(1,251,722)	(2,314,912)	(7,480,341)	(5,468,937)	(174,540,892)	(113,747,318)	(104,232,809)	(25,516,028)	(61,088,552)
WORKING CASH	(29,369,487)	(228,224)	(73,718)	(124,292)	(391,117)	(365,400)	(11,926,684)	(6,573,713)	(5,579,506)	(1,289,431)	(2,817,384)
MATERIALS, SUPPLIES & PREPAYMENTS	158,247,903	784,702	407,469	751,943	2,470,866	1,518,060	54,089,446	35,815,177	33,867,867	8,179,212	20,363,161
ACCUM. DEFERRED TAXES	(706,541,765)	(5,623,380)	(1,786,945)	(2,955,622)	(9,101,833)	(8,780,885)	(298,305,796)	(155,574,815)	(130,283,961)	(29,883,747)	(64,244,759)
REGULATORY ASSETS	57,686,546	475,679	157,692	235,706	585,482	617,164	30,669,069	10,795,411	8,450,519	1,894,213	3,805,611
DECOMMISSIONING FUND	285,200,677	2,188,437	687,285	1,281,536	4,183,938	3,652,953	98,600,144	67,083,645	59,438,957	14,638,660	33,445,123
MISCELLANEOUS DEFERRED DEBITS	39,291,625	229,406	102,131	182,456	565,141	389,294	14,984,223	8,536,562	7,822,773	1,896,357	4,583,281
OPEB	54,512,549	356,267	141,582	247,079	744,294	568,687	21,988,265	11,667,704	10,402,002	2,509,415	5,887,234
CUSTOMER ADVANCES	(44,764,989)	(141,260)	(139,627)	(228,624)	(697,879)	(375,081)	(17,171,511)	(10,472,745)	(9,086,276)	(1,911,601)	(4,538,363)
CUSTOMER DEPOSITS	(32,616,324)	(101,767)	(101,916)	(166,738)	(508,722)	(272,140)	(12,521,197)	(7,630,243)	(8,620,434)	(1,380,579)	(3,302,587)
PROFORMA ADJUSTMENTS	92,495,373	616,830	240,756	405,044	1,238,978	995,577	38,452,042	19,883,054	17,373,408	4,035,644	9,254,040
TOTAL RATE BASE	**2,077,453,821**	**15,268,509**	**5,273,880**	**8,890,949**	**27,561,160**	**24,269,586**	**856,969,967**	**454,115,496**	**391,033,266**	**90,896,430**	**203,143,039**
DEVELOPMENT OF RETURN											
BASE REVENUES FROM RATES	1,338,700,733	4,176,910	4,183,101	6,843,561	20,879,912	11,169,689	513,918,578	313,174,826	271,728,356	57,074,785	135,551,017
PROFORMA TO BASE REVENUES FROM RATES	5,225,164	(107,647)	(15,824)	(69,241)	(334,450)	175,286	(2,421,480)	(4,532,152)	2,082,092	2,766,532	7,682,056
SURCHARGE & OTHER ELECTRIC REVENUES	241,601,124	1,060,720	790,794	1,172,998	3,105,656	2,312,273	102,913,825	57,193,509	41,728,271	9,652,370	21,670,707
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(167,390,153)	(827,923)	(600,122)	(800,448)	(1,869,111)	(1,746,809)	(80,135,814)	(40,138,473)	(24,800,741)	(5,529,757)	(10,940,957)
TOTAL OPERATING REVENUES	**1,418,136,867**	**4,302,061**	**4,357,950**	**7,146,870**	**21,782,007**	**11,910,440**	**534,275,099**	**325,897,711**	**290,737,977**	**63,963,930**	**153,962,823**
OPERATING EXPENSES											
OPERATION & MAINTENANCE	913,610,715	3,469,053	2,333,488	4,238,735	13,767,520	7,668,937	294,621,579	201,857,466	205,109,984	49,673,533	130,870,421
ADMINISTRATIVE & GENERAL	56,306,993	372,921	146,388	254,131	761,785	590,266	22,953,389	12,011,206	10,660,097	2,566,380	5,982,430
DEPRECIATION & AMORT EXPENSE	130,917,006	925,913	332,892	574,322	1,792,786	1,505,922	52,004,544	28,956,469	25,284,212	5,962,722	13,577,224
AMORTIZATION ON GAIN	(1,800,581)	(13,667)	(4,345)	(8,107)	(26,468)	(22,922)	(621,071)	(423,373)	(375,914)	(92,580)	(212,093)
REGULATORY ASSETS	6,985,797	53,604	16,835	31,390	102,483	89,477	2,415,143	1,643,168	1,455,917	358,564	819,216
PROFORMA ADJUSTMENTS	(56,757,848)	(169,939)	(229,835)	(291,190)	(922,981)	(327,581)	(27,525,152)	(14,531,989)	(10,249,474)	(854,730)	(1,744,977)
TAXES OTHER THAN INCOME	41,455,832	314,164	105,999	174,370	537,117	495,859	17,592,585	9,057,283	7,643,743	1,740,833	3,793,878
INCOME TAX	147,738,669	(82,651)	734,715	975,013	2,458,536	1,000,545	79,737,662	40,922,845	21,029,870	1,731,995	(769,861)
PROFORMA INCOME TAX ADJUSTMENTS	(42,027,729)	(295,813)	(154,721)	(230,867)	(554,261)	(489,153)	(21,903,602)	(11,947,477)	(5,045,839)	(774,147)	(631,949)
TOTAL OPERATING EXPENSES	**1,196,430,854**	**4,573,565**	**3,281,418**	**5,717,796**	**18,016,497**	**10,511,350**	**419,275,077**	**267,745,597**	**255,512,596**	**60,302,570**	**151,694,389**
OPERATING INCOME	**221,706,014**	**(271,504)**	**1,076,533**	**1,429,073**	**3,765,510**	**1,399,090**	**115,000,022**	**58,152,114**	**35,225,382**	**3,661,360**	**2,268,435**
RATE OF RETURN (PRESENT)	**10.67%**	**(1.78%)**	**20.41%**	**16.07%**	**13.66%**	**5.76%**	**13.42%**	**12.81%**	**9.01%**	**4.03%**	**1.12%**
INDEX RATE OF RETURN (PRESENT)	**2.18**	**(0.36)**	**4.17**	**3.29**	**2.79**	**1.18**	**2.74**	**2.62**	**1.84**	**0.82**	**0.23**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA Corrected Distribution Cost Allocation - MDS

SUMMARY OF RESULTS	TOTAL RESIDENTIAL	RESIDENTIAL: Solar Energy Rates (E-12, ET-1 & ET-2)	Solar Demand Rates (ECT-1 & ECT-2)	E-12	ET-1 & ET-2	ECT-1 & ECT-2
DEVELOPMENT OF RATE BASE						
ELECTRIC PLANT IN SERVICE	8,539,219,424	363,747,210	17,937,027	2,623,428,113	4,025,802,113	1,508,304,961
GENERAL & INTANGIBLE PLANT	924,796,954	47,908,550	2,200,679	298,977,287	421,311,756	154,398,680
LESS: RESERVE FOR DEPRECIATION	(3,640,979,063)	(150,462,154)	(7,986,770)	(1,086,616,571)	(1,728,677,684)	(657,255,874)
OTHER DEFERRED CREDITS	(772,741,355)	(35,091,226)	(1,818,808)	(216,900,337)	(371,447,481)	(147,483,500)
WORKING CASH	(61,929,353)	(2,548,221)	(126,959)	(18,910,569)	(29,341,010)	(11,002,594)
MATERIALS, SUPPLIES & PREPAYMENTS	232,473,726	9,789,285	521,034	68,328,824	110,172,554	43,662,030
ACCUM. DEFERRED TAXES	(1,596,732,805)	(68,411,053)	(3,302,806)	(501,436,689)	(747,813,657)	(275,688,399)
REGULATORY ASSETS	187,906,442	10,478,016	434,736	68,107,919	81,721,002	27,164,768
DECOMMISSIONING FUND	434,549,532	18,565,663	1,012,884	108,810,613	217,388,521	88,771,851
MISCELLANEOUS DEFERRED DEBITS	72,097,974	3,638,271	171,803	22,896,561	33,038,562	12,352,776
OPEB	111,483,483	5,778,957	265,309	36,070,535	50,770,944	18,597,737
CUSTOMER ADVANCES	(49,850,247)	(679,199)	(76,618)	(15,137,036)	(24,414,448)	(9,542,946)
CUSTOMER DEPOSITS	(38,578,117)	(513,370)	(56,959)	(11,736,686)	(18,889,435)	(7,379,687)
PROFORMA ADJUSTMENTS	193,270,815	8,932,597	414,477	63,680,639	88,361,734	31,881,368
TOTAL RATE BASE	**4,534,987,420**	**201,133,325**	**9,607,029**	**1,439,562,423**	**2,107,883,471**	**776,801,171**
DEVELOPMENT OF RETURN						
BASE REVENUES FROM RATES	1,468,282,584	19,538,868	2,243,969	446,697,353	718,931,632	280,870,762
PROFORMA TO BASE REVENUES FROM RATES	18,295,059	3,192,150	122,765	8,426,843	5,908,510	644,792
SURCHARGE & OTHER ELECTRIC REVENUES	318,341,202	7,353,550	517,596	97,654,002	152,422,937	60,393,118
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(236,870,204)	(4,090,502)	(327,378)	(74,535,484)	(113,694,916)	(44,221,924)
TOTAL OPERATING REVENUES	**1,568,048,842**	**25,994,066**	**2,556,952**	**478,242,713**	**763,568,163**	**297,686,747**
OPERATING EXPENSES						
OPERATION & MAINTENANCE	1,020,043,692	21,957,145	1,464,395	295,633,367	494,842,690	206,146,096
ADMINISTRATIVE & GENERAL	117,457,485	6,100,168	278,798	38,190,738	53,405,004	19,482,777
DEPRECIATION & AMORT EXPENSE	263,027,757	11,746,728	571,853	81,434,351	123,158,991	46,115,834
AMORTIZATION ON GAIN	(2,729,002)	(116,504)	(6,363)	(683,914)	(1,364,650)	(557,570)
REGULATORY ASSETS	10,643,995	454,753	24,810	2,665,242	5,324,784	2,174,406
PROFORMA ADJUSTMENTS	(5,151,262)	1,952,828	62,713	(2,616,538)	(3,209,290)	(1,340,975)
TAXES OTHER THAN INCOME	94,471,605	4,026,113	193,410	30,207,543	43,952,230	16,092,309
INCOME TAX	70,542,641	(8,244,436)	9,903	25,020,846	40,459,296	13,297,033
PROFORMA INCOME TAX ADJUSTMENTS	(83,538,195)	(1,043,062)	(102,716)	(25,007,760)	(40,920,202)	(16,464,455)
TOTAL OPERATING EXPENSES	**1,484,768,715**	**36,833,732**	**2,496,802**	**444,843,875**	**715,648,852**	**284,945,454**
OPERATING INCOME	**83,279,928**	**(10,839,666)**	**60,150**	**33,398,838**	**47,919,311**	**12,741,293**
RATE OF RETURN (PRESENT)	**1.84%**	**(5.39%)**	**0.63%**	**2.32%**	**2.27%**	**1.64%**
INDEX RATE OF RETURN (PRESENT)	**0.38**	**(1.10)**	**0.13**	**0.47**	**0.46**	**0.34**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA - All Changes Combined

SUMMARY OF RESULTS	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
ELECTRIC PLANT IN SERVICE	15,326,435,253	12,962,340,167	2,364,095,086	12,962,340,167	8,539,219,424	4,125,619,728	106,444,901	126,067,867	64,988,247
GENERAL & INTANGIBLE PLANT	1,509,541,568	1,400,428,100	109,113,468	1,400,428,100	924,796,954	452,753,663	11,360,846	7,099,284	4,417,353
LESS: RESERVE FOR DEPRECIATION	(6,402,411,202)	(5,632,319,059)	(770,092,143)	(5,632,319,059)	(3,640,979,063)	(1,876,296,840)	(48,154,361)	(45,236,865)	(21,648,839)
OTHER DEFERRED CREDITS	(1,337,180,000)	(1,292,838,371)	(44,341,629)	(1,292,838,371)	(772,741,355)	(498,764,758)	(12,502,603)	(6,715,977)	(2,113,677)
WORKING CASH	(113,623,376)	(93,558,549)	(20,064,827)	(93,558,549)	(61,929,353)	(29,369,467)	(762,845)	(990,372)	(506,512)
MATERIALS, SUPPLIES & PREPAYMENTS	438,426,790	398,768,143	39,658,647	398,768,143	232,473,726	158,247,903	3,915,954	2,953,177	1,177,382
ACCUM. DEFERRED TAXES	(2,873,411,027)	(2,359,729,334)	(513,681,693)	(2,359,729,334)	(1,596,732,805)	(706,541,765)	(18,391,749)	(24,623,611)	(13,439,504)
REGULATORY ASSETS	310,940,000	250,199,222	60,740,778	250,199,222	187,906,442	57,686,546	1,483,311	1,649,074	1,473,849
DECOMMISSIONING FUND	735,196,000	731,225,942	3,970,058	731,225,942	434,549,532	285,200,677	7,291,629	3,632,160	551,943
MISCELLANEOUS DEFERRED DEBITS	121,338,000	113,265,656	8,072,344	113,265,656	72,097,974	39,291,625	977,154	579,036	319,867
OPEB	182,625,115	168,753,227	13,871,888	168,753,227	111,483,483	54,512,549	1,367,747	855,541	533,907
CUSTOMER ADVANCES	(115,609,383)	(94,903,242)	(20,706,141)	(94,903,242)	(49,850,247)	(44,764,969)	(138,265)	(149,058)	(683)
CUSTOMER DEPOSITS	(72,621,690)	(72,621,690)		(72,621,690)	(38,578,117)	(32,316,324)	(706,920)	(511,132)	(209,197)
PROFORMA ADJUSTMENTS	302,154,000	292,140,717	10,013,283	292,140,717	193,270,815	92,495,373	2,147,058	2,635,369	1,592,102
TOTAL RATE BASE	**8,011,800,048**	**6,771,150,929**	**1,240,649,119**	**6,771,150,929**	**4,534,967,420**	**2,077,453,921**	**54,331,858**	**67,241,682**	**37,136,137**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	2,909,647,523	2,865,563,427	44,084,096	2,865,563,427	1,468,282,584	1,338,700,733	29,014,733	20,979,131	8,586,247
PROFORMA TO BASE REVENUES FROM RATES	23,340,145	23,340,145		23,340,145	18,295,059	5,225,164	(275,293)	103,126	(7,912)
SURCHARGE & OTHER ELECTRIC REVENUES	582,709,014	570,735,507	11,973,507	570,735,507	318,341,202	241,601,124	7,410,721	2,550,304	832,156
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(412,607,651)	(412,186,408)	(421,243)	(412,186,408)	(236,870,204)	(167,390,153)	(5,657,567)	(1,683,140)	(585,345)
TOTAL OPERATING REVENUES	**3,103,089,031**	**3,047,452,671**	**55,636,359**	**3,047,452,671**	**1,568,048,642**	**1,418,136,867**	**30,492,595**	**21,949,421**	**8,825,146**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	1,804,920,730	1,968,494,902	(163,574,171)	1,968,494,902	1,048,787,440	884,107,924	23,537,445	9,422,004	2,640,088
ADMINISTRATIVE & GENERAL	193,799,761	176,678,975	17,120,787	176,678,975	117,457,485	56,308,993	1,414,774	915,129	582,593
DEPRECIATION & AMORT EXPENSE	456,219,756	402,496,860	53,722,896	402,496,860	263,027,757	130,917,006	3,345,705	3,422,687	1,783,706
AMORTIZATION ON GAIN	(4,626,993)	(4,601,933)	(25,060)	(4,601,933)	(2,729,002)	(1,800,581)	(45,991)	(22,882)	(3,477)
REGULATORY ASSETS	17,910,882	17,910,882		17,910,882	10,643,995	6,985,797	178,603	88,967	13,519
PROFORMA ADJUSTMENTS	(55,126,400)	(63,537,447)	8,411,047	(63,537,447)	(5,151,262)	(56,757,948)	(2,075,235)	202,523	245,374
TAXES OTHER THAN INCOME	171,499,317	139,384,353	32,114,964	139,384,353	94,471,605	41,455,832	1,075,277	1,527,822	853,817
INCOME TAX	258,174,789	224,356,180	33,818,609	224,356,180	59,591,273	158,979,233	2,185,052	2,556,185	1,044,438
PROFORMA INCOME TAX ADJUSTMENTS	(131,826,847)	(128,134,190)	(3,692,657)	(128,134,190)	(83,538,165)	(42,027,729)	(1,504,645)	(720,691)	(342,929)
TOTAL OPERATING EXPENSES	**2,710,944,995**	**2,733,048,581**	**(22,103,586)**	**2,733,048,581**	**1,502,561,096**	**1,178,168,626**	**28,109,986**	**17,391,744**	**6,817,130**
OPERATING INCOME	**392,144,036**	**314,404,090**	**77,739,945**	**314,404,090**	**65,487,546**	**239,968,242**	**2,382,609**	**4,557,677**	**2,008,016**
RATE OF RETURN (PRESENT)	**4.89%**	**4.64%**	**6.27%**	**4.64%**	**1.44%**	**11.55%**	**4.39%**	**6.78%**	**5.41%**
INDEX RATE OF RETURN (PRESENT)	**1.00**	**0.95**	**1.28**	**0.95**	**0.30**	**2.36**	**0.90**	**1.38**	**1.10**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA - All Changes Combined

SUMMARY OF RESULTS	TOTAL GENERAL SERVICE	GENERAL SERVICE									
		E-20 (Church Rate)	E-32 TOU (0-100 KW)	E-32 TOU (101-400 KW)	E-32 TOU (401+ KW)	School TOU	E-30, E-32 (0-100 KW)	E-32 (101-400 KW)	E-32 (401+ KW)	E-34	E-35
DEVELOPMENT OF RATE BASE											
ELECTRIC PLANT IN SERVICE	4,125,619,728	30,876,141	10,412,858	17,723,154	55,561,657	49,720,556	1,661,266,187	918,687,398	788,866,327	183,835,560	408,669,888
GENERAL & INTANGIBLE PLANT	452,753,663	2,961,598	1,175,500	2,052,030	6,183,930	4,728,372	182,498,666	96,951,879	86,431,844	20,853,390	48,916,454
LESS: RESERVE FOR DEPRECIATION	(1,876,295,840)	(14,001,756)	(4,597,455)	(8,197,811)	(25,793,243)	(22,658,635)	(731,082,191)	(421,306,563)	(365,815,443)	(86,953,635)	(195,790,108)
OTHER DEFERRED CREDITS	(498,764,758)	(3,124,146)	(1,251,722)	(2,314,912)	(7,480,341)	(5,468,937)	(174,540,992)	(113,747,318)	(104,232,809)	(25,515,026)	(61,088,552)
WORKING CASH	(29,369,467)	(228,224)	(73,716)	(124,292)	(391,117)	(365,400)	(11,926,684)	(6,573,713)	(5,579,506)	(1,289,431)	(2,817,384)
MATERIALS, SUPPLIES & PREPAYMENTS	158,247,903	784,702	407,469	751,943	2,470,866	1,518,060	54,089,446	35,815,177	33,867,867	8,179,212	20,363,161
ACCUM. DEFERRED TAXES	(706,541,765)	(5,623,389)	(1,786,945)	(2,955,622)	(9,101,833)	(8,780,885)	(298,306,798)	(155,574,815)	(130,283,961)	(29,883,747)	(64,244,759)
REGULATORY ASSETS	57,686,546	475,679	157,692	235,706	585,482	617,164	30,669,069	10,795,411	8,450,519	1,894,213	3,805,611
DECOMMISSIONING FUND	285,200,677	2,188,437	687,285	1,281,536	4,183,938	3,652,953	98,600,144	67,083,645	59,438,957	14,638,660	33,445,123
MISCELLANEOUS DEFERRED DEBITS	39,291,625	229,406	102,131	182,456	565,141	389,294	14,984,223	8,536,562	7,822,773	1,896,357	4,583,281
OPEB	54,512,549	356,287	141,582	247,079	744,294	568,687	21,988,265	11,667,704	10,402,002	2,509,415	5,887,234
CUSTOMER ADVANCES	(44,764,989)	(141,280)	(139,627)	(228,624)	(697,879)	(375,081)	(17,171,511)	(10,472,745)	(9,088,278)	(1,911,601)	(4,538,363)
CUSTOMER DEPOSITS	(32,616,324)	(101,767)	(101,916)	(166,738)	(508,722)	(272,140)	(12,521,197)	(7,830,243)	(6,620,434)	(1,390,579)	(3,302,587)
PROFORMA ADJUSTMENTS	92,495,373	616,830	240,756	405,044	1,238,978	985,577	38,452,042	19,883,054	17,373,408	4,035,644	9,254,040
TOTAL RATE BASE	**2,077,453,921**	**15,268,509**	**5,273,890**	**8,890,949**	**27,561,150**	**24,289,585**	**856,999,867**	**454,115,436**	**391,033,265**	**90,898,430**	**203,143,039**
DEVELOPMENT OF RETURN											
BASE REVENUES FROM RATES	1,338,700,733	4,176,910	4,183,101	6,843,561	20,879,912	11,169,689	513,918,578	313,174,826	271,728,356	57,074,785	135,551,017
PROFORMA TO BASE REVENUES FROM RATES	5,225,164	(107,647)	(15,824)	(69,241)	(334,450)	175,286	(2,421,490)	(4,532,152)	2,082,092	2,766,532	7,682,056
SURCHARGE & OTHER ELECTRIC REVENUES	241,601,124	1,060,720	790,794	1,172,998	3,105,656	2,312,273	102,913,825	57,193,509	41,728,271	9,652,370	21,670,707
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(167,390,153)	(827,923)	(600,122)	(800,448)	(1,869,111)	(1,746,809)	(80,135,814)	(40,138,473)	(24,800,741)	(5,529,757)	(10,940,957)
TOTAL OPERATING REVENUES	**1,418,136,867**	**4,302,061**	**4,357,950**	**7,146,870**	**21,782,007**	**11,910,440**	**534,275,089**	**325,897,711**	**290,737,977**	**63,963,930**	**153,962,823**
OPERATING EXPENSES											
OPERATION & MAINTENANCE	884,107,924	3,655,615	2,358,177	4,278,542	13,889,827	7,927,209	299,623,543	202,875,571	189,529,928	45,591,049	114,378,461
ADMINISTRATIVE & GENERAL	56,308,993	372,921	146,388	254,131	761,785	590,266	22,953,389	12,011,206	10,660,097	2,566,380	5,992,430
DEPRECIATION & AMORT EXPENSE	130,917,006	925,913	332,892	574,322	1,792,786	1,505,922	52,004,544	28,956,469	25,284,212	5,962,722	13,577,224
AMORTIZATION ON GAIN	(1,800,581)	(13,687)	(4,345)	(6,107)	(26,468)	(22,922)	(621,071)	(423,373)	(375,914)	(92,580)	(212,093)
REGULATORY ASSETS	6,985,797	53,604	16,835	31,390	102,483	89,477	2,415,143	1,643,166	1,455,917	358,564	819,216
PROFORMA ADJUSTMENTS	(56,757,843)	(169,939)	(228,835)	(291,190)	(922,981)	(327,561)	(27,525,152)	(14,531,999)	(10,249,474)	(664,730)	(1,744,977)
TAXES OTHER THAN INCOME	41,455,832	314,164	105,999	174,370	537,117	495,859	17,592,585	9,057,283	7,643,743	1,740,833	3,793,878
INCOME TAX	158,979,233	(153,731)	725,308	959,846	2,411,937	902,144	77,831,914	40,534,946	26,965,871	3,287,421	5,513,576
PROFORMA INCOME TAX ADJUSTMENTS	(42,027,729)	(295,813)	(154,721)	(230,867)	(554,261)	(489,153)	(21,903,602)	(11,947,477)	(5,045,839)	(774,147)	(631,849)
TOTAL OPERATING EXPENSES	**1,178,168,826**	**4,689,047**	**3,296,699**	**5,742,437**	**18,092,206**	**10,671,221**	**422,371,283**	**268,175,804**	**245,868,541**	**57,775,512**	**141,485,866**
OPERATING INCOME	**239,968,242**	**(386,987)**	**1,061,251**	**1,404,433**	**3,689,801**	**1,239,219**	**111,903,806**	**57,521,906**	**44,869,436**	**6,188,418**	**12,476,957**
RATE OF RETURN (PRESENT)	**11.55%**	**(2.53%)**	**20.12%**	**15.80%**	**13.39%**	**5.11%**	**13.06%**	**12.67%**	**11.47%**	**6.81%**	**6.14%**
INDEX RATE OF RETURN (PRESENT)	**2.36**	**(0.62)**	**4.11**	**3.23**	**2.74**	**1.04**	**2.87**	**2.59**	**2.34**	**1.39**	**1.25**

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2015 Test Year Adjusted Cost of Service Study
FEA - All Changes Combined

SUMMARY OF RESULTS	TOTAL RESIDENTIAL	RESIDENTIAL				
		Solar Energy Rates (E-12, ET-1 & ET-2)	Solar Demand Rates (ECT-1 & ECT-2)	E-12	ET-1 & ET-2	ECT-1 & ECT-2
DEVELOPMENT OF RATE BASE						
ELECTRIC PLANT IN SERVICE	8,539,219,424	363,747,210	17,937,027	2,623,428,113	4,025,802,113	1,508,304,961
GENERAL & INTANGIBLE PLANT	924,796,954	47,908,550	2,200,679	298,977,287	421,311,756	154,398,680
LESS: RESERVE FOR DEPRECIATION	(3,540,979,053)	(160,462,154)	(7,986,770)	(1,086,616,571)	(1,728,677,684)	(657,255,874)
OTHER DEFERRED CREDITS	(772,741,355)	(35,031,228)	(1,818,809)	(216,900,337)	(371,447,481)	(147,483,500)
WORKING CASH	(61,929,353)	(2,548,221)	(128,959)	(18,910,569)	(29,341,010)	(11,002,594)
MATERIALS, SUPPLIES & PREPAYMENTS	232,473,726	9,789,285	521,034	68,328,824	110,172,554	43,662,030
ACCUM. DEFERRED TAXES	(1,596,732,805)	(68,411,053)	(3,302,806)	(501,436,880)	(747,913,657)	(275,668,369)
REGULATORY ASSETS	187,906,442	10,478,018	434,736	68,107,919	81,721,002	27,164,768
DECOMMISSIONING FUND	434,549,532	18,565,663	1,012,884	108,810,613	217,388,521	88,771,851
MISCELLANEOUS DEFERRED DEBITS	72,097,974	3,638,271	171,803	22,896,561	33,038,562	12,352,776
OPEB	111,483,483	5,778,957	265,309	36,070,535	50,770,944	18,597,737
CUSTOMER ADVANCES	(49,850,247)	(679,199)	(76,619)	(15,137,036)	(24,414,448)	(9,542,946)
CUSTOMER DEPOSITS	(38,578,117)	(513,370)	(56,959)	(11,736,886)	(18,889,435)	(7,379,687)
PROFORMA ADJUSTMENTS	193,270,815	8,932,597	414,477	63,680,639	88,361,734	31,881,368
TOTAL RATE BASE	**4,534,987,420**	**201,133,326**	**9,807,029**	**1,439,582,423**	**2,107,883,471**	**776,801,171**
DEVELOPMENT OF RETURN						
BASE REVENUES FROM RATES	1,468,282,584	19,538,868	2,243,969	446,697,353	718,931,632	280,870,762
PROFORMA TO BASE REVENUES FROM RATES	18,295,059	3,192,150	122,765	8,426,843	5,908,510	644,792
SURCHARGE & OTHER ELECTRIC REVENUES	318,341,202	7,353,550	517,596	97,654,002	152,422,937	60,393,118
PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(236,870,204)	(4,090,502)	(327,376)	(74,535,484)	(113,694,916)	(44,221,924)
TOTAL OPERATING REVENUES	**1,568,048,642**	**25,994,066**	**2,556,952**	**478,242,713**	**763,568,163**	**297,686,747**
OPERATING EXPENSES						
OPERATION & MAINTENANCE	1,048,787,440	23,537,499	1,542,795	302,306,536	509,479,646	211,920,965
ADMINISTRATIVE & GENERAL	117,457,485	6,100,168	278,798	38,190,738	53,405,004	19,482,777
DEPRECIATION & AMORT EXPENSE	263,027,757	11,746,728	571,853	81,434,351	123,158,991	46,115,834
AMORTIZATION ON GAIN	(2,728,002)	(116,504)	(6,363)	(683,914)	(1,364,650)	(557,570)
REGULATORY ASSETS	10,843,995	454,753	24,810	2,665,242	5,324,784	2,174,406
PROFORMA ADJUSTMENTS	(5,151,262)	1,952,828	62,713	(2,616,538)	(3,209,290)	(1,340,975)
TAXES OTHER THAN INCOME	94,471,605	4,026,113	193,410	30,207,543	43,952,230	16,092,309
INCOME TAX	59,591,273	(8,846,551)	(19,068)	22,478,369	34,882,615	11,096,807
PROFORMA INCOME TAX ADJUSTMENTS	(83,538,196)	(1,043,062)	(102,718)	(25,007,760)	(40,920,202)	(16,464,455)
TOTAL OPERATING EXPENSES	**1,502,561,096**	**37,811,971**	**2,545,332**	**448,974,566**	**724,709,128**	**288,520,098**
OPERATING INCOME	**65,487,546**	**(11,817,905)**	**11,620**	**29,268,147**	**38,859,035**	**9,166,649**
RATE OF RETURN (PRESENT)	**1.44%**	**(5.88%)**	**0.12%**	**2.03%**	**1.84%**	**1.18%**
INDEX RATE OF RETURN (PRESENT)	**0.30**	**(1.20)**	**0.02**	**0.42**	**0.38**	**0.24**

Exhibit AMA-5

ARIZONA PUBLIC SERVICE COMPANY

Docket No. E-01345A-16-0036

Base Revenues and Proposed Increases by Class

					Company Proposed				FEA Proposed			
Line	Description	Present Base Rate Revenues (000) (1)	Adjustor Revenue Increase (000) (2)	FEA COSS Present ROR Index (3)	Proposed Base Rate Increase (000)* (4)	Percent Increase (5)	Index Increase (6)	Proposed ROR Index** (7)	Proposed Base Rate Increase (000)* (8)	Percent Increase (9)	Index Increase (10)	Proposed ROR Index (11)
	Residential											
1	Residential Solar (Energy Rates)	$ 22,731	$ 2,648	(1.27)	$ 1,739	7.7%	1.33	(0.53)	$ 2,610	11.5%	2.00	(0.49)
2	Residential Solar (Demand Rates)	2,367	240	0.03	217	9.2%	1.60	0.36	204	8.6%	1.50	0.35
3	Residential E-12	455,124	51,044	0.44	36,791	8.1%	1.41	0.68	39,201	8.6%	1.50	0.69
4	Residential ET-1 & ET-2	724,840	81,796	0.40	58,092	8.0%	1.40	0.69	62,432	8.6%	1.50	0.71
5	Residential ECT-1 & ECT-2	281,516	32,880	0.25	21,450	7.6%	1.33	0.64	24,247	8.6%	1.50	0.67
6	Total Residential	$ 1,486,578	$ 168,607	0.31	$ 118,289	8.0%	1.39	0.62	$ 128,694	8.7%	1.51	0.64
	General Service											
7	E-20 (Church Rate)	$ 4,069	$ 461	(0.55)	$ 366	9.0%	1.57	0.09	$ 366	9.0%	1.57	0.09
8	E-32 TOU (0-100 kW)	4,167	333	4.33	26	0.6%	0.11	2.83	-	0.0%	0.00	2.79
9	E-32 TOU (101-400 kW)	6,774	483	3.40	309	4.6%	0.79	2.48	231	3.4%	0.59	2.41
10	E-32 TOU (401+ kW)	21,209	1,097	2.88	1,265	6.0%	1.04	2.17	1,020	4.8%	0.84	2.11
11	School TOU	11,345	1,059	1.10	687	6.1%	1.05	1.11	556	4.9%	0.85	1.07
12	E-30, E-32 (0-100 kW)	511,454	43,872	2.81	178	0.0%	0.01	1.89	-	0.0%	0.00	1.89
13	E-32 (101-400 kW)	308,825	23,705	2.73	12,373	4.0%	0.70	2.04	8,804	2.9%	0.50	1.99
14	E-32 (401+ kW)	273,007	13,851	2.47	16,568	6.1%	1.06	1.89	13,414	4.9%	0.86	1.83
15	E-34	59,842	3,186	1.47	4,003	6.7%	1.16	1.36	3,311	5.5%	0.96	1.31
16	E-35	143,235	6,362	1.32	8,468	5.9%	1.03	1.24	6,812	4.8%	0.83	1.18
17	Total General Service	$ 1,343,926	$ 94,408	2.49	$ 44,242	3.3%	0.57	1.82	$ 34,513	2.6%	0.45	1.79
18	E-221 (Water Pumping)	28,739	3,243	0.94	1,649	5.7%	1.00	1.16	1,317	4.6%	0.80	1.11
19	Street Lighting	21,082	981	1.46	1,149	5.5%	0.95	1.02	906	4.3%	0.75	0.99
20	Dusk to Dawn	8,578	313	1.16	554	6.5%	1.12	0.80	455	5.3%	0.92	0.78
21	Total Retail	$ 2,888,904	$ 267,551	1.00	$ 165,884	5.7%	1.00	1.00	$ 165,884	5.7%	1.00	1.00
									1.5 x System Average:	8.6%		
									2.0 x System Average:	11.5%		

Notes:

*Net of Adjustor Transfer

**Using FEA COSS Model